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SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS. LA CYGNE STATION, KANSAS CITY POWER AND LIGHT COMPANY AND KANSAS GAS AND ELECTRIC COMPANY

Gerald A. Isaacs, et al

PEDCo-Environmental Specialists, Incorporated

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SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS

LA CYGNE STATION, KANSAS CITY POWER AND LIGHT CO. AND KANSAS GAS AND ELECTRIC CO.

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16. ABSTRACT

The report gives results of a survey of the wet limestone flue gas desulfurization (FGD) system at the La Cygne Station of Kansas City Power and Light Co. and Kansas Gas and Electric Co. The FGD system, designed and installed by the Babcock and Wilcox Co., was built integral with the electric power generating facility. The system consists of seven modules for particulate and SO2 removal, with on-site limestone grinding and storage facilities. Since there is no provision for bypassing flue gas around the FGD modules, all flue gases are treated. Several modifications have been made since system start-up in February 1973. A particulate removal efficiency of 97-99% has been reported. SO2 removal efficiency ranges between 70 and 83%. The spent limestone slurry is discharged to a 160-acre pond, and water from the pond is recycled. The initial installed capital cost of the FGD system was $34 million or $41/KW (based on a net rated capacity of 820 MW) in 1973. Subsequent modifications increased the cost to about $45 million or $55/KW. Estimated operating and maintenance costs, including limestone, are 1.79 mills/KWH, not including capital charges.

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SUMMARY

The wet limestone flue gas desulfurization system at the La Cygne Power Station of the Kansas City Power and Light Company was designed and installed by The Babcock and Wilcox Company. It was built as an integral part of the electric power generating facility.

The system consists of seven particulate and SO_2 scrubbing modules, with on-site limestone grinding and storage facilities. All flue gases are treated, and the ductwork does not provide for the bypassing of flue gas around the modules.

Since the system was first placed in service in February 1973, several modifications have been made to alleviate the many operating problems associated with an undertaking of this magnitude. At the present time, a particulate efficiency of 97 to 99 percent is being attained. The SO_2 removal efficiency ranges between 70 and 83 percent.

The spent limestone slurry is discharged to a 160-acre pond. Water from the pond is recycled for use in the process.

The initial installed capital cost of the flue gas desulfurization system was $34 million, or $41/KW (based on a net rated capacity of 820 MW). Subsequent equipment modi-

fications have increased the cost to about $45 million or $55/KW. The estimated cost for maintenance and operation of the system, including limestone, is 1.79 mills/KWH. This figure does not include any capital charge to account for amortization, interest or taxes.

Pertinent data on the facility and the FGD system are presented below.

SUMMARY OF FGD DATA, LA CYGNE POWER STATION

Unit rating, MW (net)	820
Fuel:	Coal
BTU/lb	8,200 to 10,200
Ash, percent	20-30
Sulfur, percent	5-6
FGD vendor	Babcock and Wilcox
Process	Wet limestone scrubbing
New or retrofit	New
Start-up date	February 1973
FGD modules	7
Efficiency, percent:	
Particulates	97-99
SO_2	70-83
Sludge disposal	Unstabilized sludge disposed in unlined pond.
Unit cost	Capital, $55/KW; operating cost estimated at 1.79 mills/KWH, not including amortization, taxes, and insurance.

1.0 INTRODUCTION

The Control Systems Laboratory of the U.S. Environmental Protection Agency (EPA) has initiated a study to evaluate the performance characteristics and degree of reliability of flue gas desulfurization (FGD) systems on coal-fired boilers in the United States. This report on the La Cygne Power Station of Kansas City Power and Light Company (KCP&L) is one of a series of reports on such systems, which presents values of key process design and operating parameters, describes the major start-up and operational problems encountered at the facility and the measures taken to alleviate such problems, and identifies the total installed and annualized operating costs.

This report is based upon information obtained during a plant inspection on June 5, 1974, and on data provided by KCP&L and Babcock and Wilcox (B&W) personnel during that visit and subsequent to it.

Section 2.0 presents pertinent data on facility design and operation, including actual and allowable particulate and SO_2 emission rates. Section 3.0 describes the FGD system, and Section 4.0 analyzes FGD system performance. Appendices present details of plant and system operation and photos of the installation.

2.0 FACILITY DESCRIPTION

The La Cygne Power Station of KCP&L is a new station. It is located about 55 miles south of Kansas City, in Linn County, Kansas. The terrain around the station is relatively flat pasture land, and there is no other major industry in the area. The nearest populated area is the town of La Cygne, about 6 miles west of the station. The boiler was first fired in December, 1972. The power generating facilities were placed in service on May 31, 1973.

The electric power generating facilities consist of one 6,200,000 lb steam/hr, coal-fired, base-load boiler with associated 820 MW (net) steam turbine and electric generator. The plant also has three oil-fired boilers, used primarily for start-up of the large unit, but also to supply steam to a 22 MW house turbine generator.

The boiler at La Cygne, designed by B&W is a wet-bottom, cyclone-fired unit. The pollution control equipment on this boiler, which consists of seven scrubbing modules, was also built by B&W as an integral part of the power generating facilities. Bypassing of the boiler's flue gas around the FGD system is not possible. The La Cygne Power Station uses about 50 MW from its gross generating capacity of 870 MW to operate the station equipment including the FGD system.

The coal now being burned ranges in gross heating value (as-received) between 8200 and 10,200 BTU per pound. Ash and sulfur range 20-30 percent and 5-6 percent, respectively.

The maximum particulate emission allowed under the Kansas State Department of Health and Environment Regulation No. 28-19-31-A is 0.13 lb/MM BTU of heat input to the boiler. The present atmospheric emission of particulates from the FGD system is equivalent to 0.15 lb/MM BTU.

Atmospheric emissions of sulfur dioxide are limited by Regulation No. 28-19-31-C, under which the maximum allowable emission of sulfur dioxide is 1.5 lb/MM BTU of heat input to the boiler. The present SO_2 emission rate from the La Cygne station, based on 80 percent removal efficiency in the FGD system, is equivalent to about 2 lb/MM BTU. This figure is based on 95 percent conversion of sulfur to sulfur dioxide.

Table 2.1 presents pertinent data on plant design, operation, and atmospheric emissions.

Table 2.1 PERTINENT DATA ON PLANT DESIGN, OPERATION AND ATMOSPHERIC EMISSIONS

Maximum generating capacity, MW (net)	820
Boiler capacity factor (1974), %	21
Served by stack No.	1
Boiler manufacturer	B&W
Year placed in service	1973
Maximum coal consumption, ton/hr	404
Maximum heat input, MM BTU/hr	7676
Unit heat rate, BTU/KWH	9360
Stack height above grade, ft.	700
Flue gas rate-maximum, acfm	2,760,000
Flue gas temperature, °F	285
Emission controls:	
Particulate	Venturi scrubber
SO_2	Venturi scrubber and countercurrent tray absorber tower
Particulate emission rate:	
Allowable, lb/MM BTU	0.13
Actual, lb/MM BTU	0.15
SO_2 emission rate:	
Allowable, lb/MM BTU	1.5
Actual, lb/MM BTU	2

3.0 FLUE GAS DESULFURIZATION SYSTEM

3.1 PROCESS DESCRIPTION

The FGD system consists of seven identical scrubbing modules (one is shown in Figure 3.1) with a venturi scrubber for particulate emission control and an absorber tower for SO_2 emission control. Each module treats about one-seventh of the total flue gas from the coal-fired boiler, or about 394,300 acfm. As the hot flue gas enters the venturi, it is subjected to jets of limestone slurry injected through nozzles on the walls of the vessel. The liquid-gas stream flows downward through the venturi throat restriction, where the gas molecules contact the atomized liquid droplets. The scrubbing efficiency is regulated by adjusting the venturi throat gap. As the gas exits from the venturi and enters the disengagement chamber, its velocity decreases from about 130 ft/sec (at the throat) to about 15 ft/sec. This reduction in velocity separates the limestone slurry droplets from the quenched gas. The slurry drains into the recirculation tank. The gas enters the SO_2 absorber tower at the base and moves upward through two sieve trays in series. As the gas passes through the 1 3/8-inch-diameter holes of the sieve trays, it contacts a shower of limestone slurry, which is sprayed in the path of the rising gas. The scrubbed gas

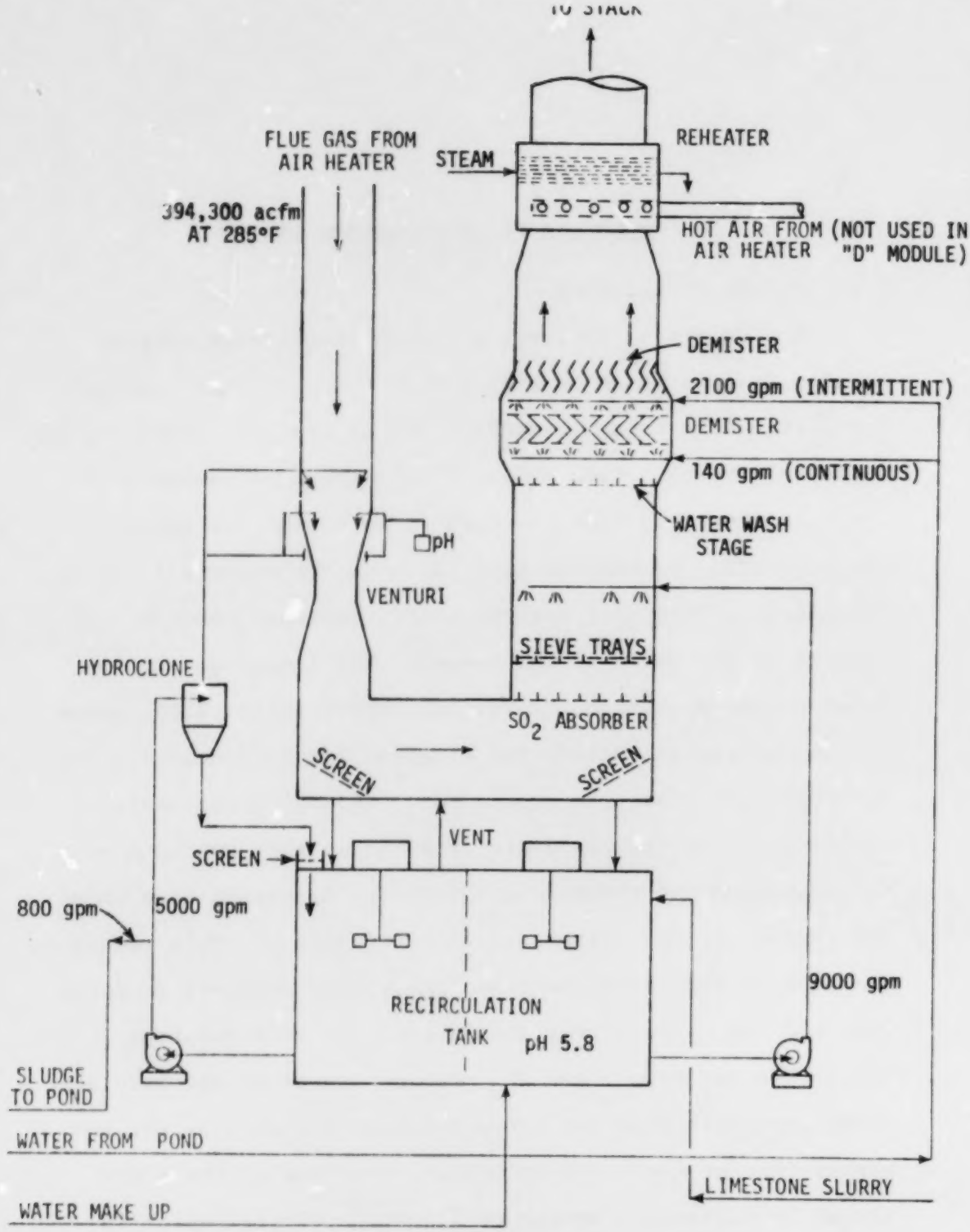

Figure 3.1 Flow diagram of one of the seven FGD modules.

then passes through a third sieve tray which collects slurry carryover and reduces the load on the demister. The gas then passes through a 10-inch high "Z" shape demister where the remaining fine droplets coalesce and drip back down through the gas stream into the recirculation tank. Two of the seven modules also incorporate a second stage demister. The flue gas is then reheated from about 121° to 175°F. Reheating is accomplished primarily by means of steam coils, with additional heat provided by injecting hot air from the boiler combustion air heater. This latter practice, which was not included in the original design of the system, has reduced the net generating capacity of the unit by approximately 30 to 60 MW. The additional reheat was found to be necessary to prevent deterioration of the reheat steam coils. Finally the reheated gas enters a plenum common to all modules and is discharged to the stack through induced-draft fans.

The venturi and the absorber tower of each module share a common limestone slurry recirculation tank, in which the pH is maintained between 5.5 and 6.0. The pH is monitored by means of a cell located in the slurry feed to the venturi nozzles. The limestone solids content of the slurry at this point is about 10 percent. Bags of lime are stored nearby for manual addition to the slurry if its acidity increases because of low quality limestone.

For removal of large particles of scale from the recirculated liquor, a liquid cyclone has been installed on each module. These liquid cyclones centrifugally separate

the large particles of scale from the liquor and discharge them to the recirculation tank through a screen. This helps prevent plugging of nozzles and strainers and reduces erosion in pumps, pipes, and nozzles.

The liquid level in the recirculation tank is maintained by pumping excess liquor to the sludge disposal pond; this plant requires no facilities for sludge treatment or fixation. The 160-acre pond is estimated to be sufficient for four years of production at rated boiler capacity.

Limestone is ground on site. A 60,000 ton supply of limestone rocks is maintained near the coal storage area. The limestone is transported intermittently to the mill by the coal conveyor system. Two wet ball mills, each rated at 108 ton/hr are housed in a building that also contains two limestone holding tanks. The seven scrubbing modules are located inside a building between the boiler and the stack.

3.2 DESIGN PARAMETERS

The FGD installation was designed with venturi and turbulent contact absorber (TCA) towers for fly ash and SO_2 removal. Many major modifications in the system have since altered some of the original design parameters; the following description represents current operating conditions.

The venturi scrubber operation was originally designed for a liquid-to-gas ratio (L/G) of 18 gallons per 1000 cubic feet of gas. Since installation of the hydroclone unit, however, the pressure head of the recirculation pump has increased so that the L/G is only about 12 gallons per 1000

cubic feet of gas. The liquid recirculation rate is 4000 gpm. Gas velocity through the venturi throat is about 150 ft/sec with the throat wide open.

The SO_2 absorber tower is designed for an L/G of about 26.5 gallons per 1000 cubic feet of gas. Gas velocity through the demister section of the tower is 8.4 ft/sec. Liquid recirculation rate in the absorber tower was designed for 9000 to 11,000 gpm.

The tower demisters are washed by underspray and overspray manifolds. Pond water is used for cleaning. Each demister is washed continuously with 140 gpm of underspray water. The overspray operates intermittently at 2100 gpm for 1 minute during each 8-hour period.

The reheater tube bundles were originally made of 304 stainless steel units. The original design reheater exit temperature was 147°F. As noted earlier, supplemental direct heating with hot air injection is presently practiced on six modules. The remaining module has 4 rows of reheater bundles with plans calling for the addition of three or four more to raise the temperature to 175°F.

Tables 3.1, 3.2 and 3.3 summarize operating and design parameters and specifications for the major components of the FGD system.

Table 3.1 SUMMARY OF DATA:

PARTICULATE AND SO_2 SCRUBBERS

	Venturi scrubber	SO_2 scrubber tower
L/G gallons/1000 acf	12	26.5
Superficial gas velocity, ft/sec	147	8.4 (at demister)
Dimensions	21-1/2' long x 22" wide	32' x 16' x 65' high
Equipment internals	Adjustable throat	Sieve trays (1 3/8-inch-diameter holes)
Material of constuction		
Shell	316L SS	316L SS (no liner)
Internals	Throat, Kaocrete ceramic, venturi throat blocks	316L SS

Table 3.2 SUMMARY OF DATA: FGD SYSTEM HOLD TANKS

	Recirculation tank	Limestone slurry make-up tank
Total number of tanks	7	2
Dimensions, ft	30 dia. x 24 high	36 dia. x 26 high
Retention time at full load, minutes	8	120
Temperature, °F	121	ambient
pH	5.5-6.0	7.5
Limestone concentration, %	8 to 10	20
Total solids concentration, %	14	
Specific gravity		
Material of construction	Rubber-lined carbon steel	Rubber-lined carbon steel

Table 3.3 TYPICAL PRESSURE DROP ACROSS COMPONENTS OF FGD TRAIN

Equipment	Pressure drop, inches W.G.
Venturi scrubber	7
SO_2 absorber trays	6
Water wash tray	1.2
Demister	0.2
Reheater	3.7
Ductwork	4
Total FGD system	22

3.3 INSTALLATION SCHEDULE

Construction was started in April 1969 and reached the halfway point in October 1971 with a construction force of over 900 men. Unit No. 1 was nearly complete when the boiler was first fired on December 26, 1972. Construction was considered complete when the generating unit was declared commercial on June 1, 1973. There were no major construction delays. Construction was terminated on schedule.

3.4 COST DATA

The installed capital cost of the FGD system was initially $34 million, or $41/KW (based on net rated capacity of 820 MW). Subsequent equipment modifications are expected to increase this cost to about $45 million or $55/KW. The present annualized operating cost is about 1.79 mills/KWH. This figure does not include amortization, interest or taxes. About 51 people are required to man the scrubber operation which includes the scrubbers, the induced-draft fans, and the mill house. This number includes 27 operators and cleanup men, 1 process attendant, 1 superintendent, 1 engineer and 16 maintenance men. This is a research manpower situation. The number of operating personnel may be reduced at a later date.

4.0 FGD SYSTEM PERFORMANCE

4.1 GENERAL DISCUSSION

The FGD installation on the La Cygne Boiler No. 1 has been plagued with numerous problems since the first trial operation of the boiler on December 26, 1972. Some of these problems, such as the vibrations of the induced-draft fans and their sensitivity to imbalance, appeared even before the boiler was fired.

When these fabrication problems were corrected and the FGD system was put in operation, other problems began to appear. Some of these problems are associated with the wet limestone process and have been encountered in similar installations; they include plugging of the demister and strainers, erosion of spray nozzles, and corrosion of reheater tubes.

KCP&L recognizes that the high fly ash content of the flue gas is responsible for a great percentage of these problems. Operating personnel are now having increased success in minimizing the effects of fly ash deposits.

A portion of the heated boiler combustion air is drawn from the air heater outlet and bled into the scrubber exhaust stream ahead of the reheat tube bundles. Capital and operating costs associated with this system have not been reported, but the procedure reduces the capacity of the boiler by

about 30 to 60 MW, based on a recent full load test. The bleed in air has been necessary to protect the reheat tube bundles from corrosion, but is being phased out by installing reheat tubes of more acid and chloride ion resistant metals.

Because the FGD system includes no spare modules and cannot be bypassed, output of the boiler is totally controlled by the performance and availability of the FGD modules. At the present time, each module is shut down about once per week during off peak hours for cleaning. It is hoped that the operating period can be extended to minimize the impact of module shutdown on operation of the system. The present goal is to reduce the frequency of shutdown to once every 3 weeks, with all maintenance to be performed by the night shift.

Availability data for 1974 appear in Table 4.1. For the year the boiler was on-line 4578 hours, or 52 percent of the time. Calculating availability as the percent ratio of FGD module operating hours to boiler operating hours, the monthly availabilities of individual modules ranged from 23 percent to 100 percent. Yearly module availabilities ranged from 69 percent to 85 percent. The average module utilization over the one-year period was 77 percent.

4.2 START-UP PROBLEMS AND SOLUTIONS

Analysis of problems encountered during and since start-up reveals that nearly all were due to mechanical design rather than to process chemistry. An account of the major problems follows.

Table 4.1 MODULE AVAILABILITY SUMMARY - LA CYGNE, 1974

Month	Boiler hours	Module hours/availability (%)							Average availability[a]
		Module A	Module B	Module C	Module D	Module E	Module F	Module G	
January	364	179/49	115/32	161/44	315/87	83/23	133/37	295/81	50
February	364	239/66	247/68	213/59	278/76	189/52	364/100	237/65	69
March									--
April	332	222/67	233/70	249/75	293/88	245/74	332/100	291/88	80
May	500	344/69	415/83	390/78	426/85	389/78	422/84	399/80	80
June	480	441/92	402/84	400/83	433/90	393/82	396/83	418/87	86
July	313	236/75	252/80	256/80	253/81	256/85	248/79	241/77	80
August	571	514/90	512/90	415/73	460/81	463/81	448/78	507/99	85
September	606	417/69	532/88	444/73	458/76	503/83	539/89	518/86	81
October	662	472/71	402/61	391/59	535/81	520/79	615/93	588/89	76
November	386	347/90	273/71	230/60	235/61	324/84	327/85	323/84	76
December									--
Total	4578	3411/75	3383/74	3149/69	3686/81	3375/74	3824/84	3817/83	77%

[a] Does not include module reserve (or standby) time.

1. Scrubber Modules: The process piping network is all rubber-lined to protect the carbon steel base from the abrasive slurry. In general, the rubber liners have performed well, with only a few reported incidents of wear in the area of the spent slurry valves. This wear was attributed to the throttling action of the valve to modulate the flow of slurry. The problem was solved by operating the valve only in a completely open or completely closed position.

The venturi pumps on the circulation tanks are also rubber lined; this lining has been damaged many times, primarily because of plugging of the strainer at the suction end of the pump. As the flow ceases or is drastically reduced because of this plugging, the pump cavitates and the liner is sucked into the path of the impeller and shredded. The suction strainers plugged frequently. Since they were located inside the recirculation tank, the tank had to be drained for cleaning of the strainers. To extend the life of the limestone slurry spray nozzles on the venturi scrubber and to reduce wear and erosion in the slurry recirculation loop, a hydroclone was installed in the recirculation line of each module. This device separates the larger particles of scale from the main slurry steam by means of centrifugal action. This modification, made at a cost of about $13,000 per module, allowed the removal of the strainer and thereby corrected the pump problems.

In the past the demister trays and the gas reheater tubes have plugged severely. The demister trays are made up

of Z-shaped fiberglass boards. Droplets of slurry are carried over with the flue gas and are deposited on the demister trays. As the slurry builds up, the gas flow is restricted and its velocity through the demister increases. This leads to solids carryover and deposition on the reheater tubes. The slurry carryover also reaches the induced-draft fan and is deposited on its blades.

These interrelated problems of carryover to the demister, the reheater, and the induced-draft fan have necessitated many modifications and corrections of operating procedures. Currently, intermittent heavy overspray and continuous underspray have kept the demisters relatively clean. Steam soot blower modifications have been reasonably successful in maintaining the reheaters and fan washing has been greatly reduced.

The original reheater tubes (304 SS) began to fail prematurely because of attack by acid condensate. They are now being replaced with 316L SS bundles. In order to prevent acid condensation, hot air headers were installed upstream of the reheater coils and a hot slip stream from the boiler's air heater was used to provide the additional reheat capability to raise the temperature to 190-200°F. It is expected that the 316L SS reheaters will be able to withstand corrosion at about 175°F so that the boiler air heater bleed requirement can be reduced or eliminated.

2. Induced-Draft Fans: Since the time these fans were first balanced in September 1972 they have been a constant source of trouble. One problem was severe vibration in the

fan housing. The fans were initially sensitive to imbalance, and it was found that the operating speed was close to the critical speed. The vibrations caused cracks to appear in the inlet cones, requiring additional stiffeners to strengthen the housing.

Another problem was the high running temperature of the thrust collars on the fan bearings. Temperatures reached the 180°F alarm set point within a short time after the fans were started. Examination of the bearings revealed that the thrust collars were not stable. The movement attributed to air turbulence in the inlet ductwork caused the rotor to shift from side to side. Several aerodynamic configurations were tried to eliminate air turbulence. A splitter foil and directional vanes were installed in the duct and in the fan inlet box, but the thrust collar continued to overheat and to move during operation. The temperature increase was finally controlled by cutting oil grooves in the thrust collar and installing forced-lubrication systems on all the fans. These modifications caused the thrust collar temperature to drop into a range from 140°F to 160°F. Movement of the thrust collar was checked by installing split backup collars designed to give an interference fit.

Problems with the induced-draft fans occurred as soon as the boiler was fired. As mentioned earlier, fly ash and slurry were carried over from the scrubber and deposited on the blades of the impeller, aggravating the tendency for the fan to be out of balance.

Fan sensitivity to imbalance was complicated by the fly ash eroding the fan blades. One blade was found to be nearly destroyed by erosion. Examination of all the blades by magnaflux revealed several cracks indicating the need for reinforcment. By June 1974 all I.D. fan rotors had been exchanged with units of heavier design. Shaft diameter was increased from 20" to 24". The wheels radial tip blades and side plates are 5/8" thick instead of 1/4". The thick center plate was scalloped to hold down the weight and the critical frequency was moved farther away from the operating speed to reduce the tendency to vibrate. The leading edge of each blade was covered with a stainless steel clip to deter erosion. Fly ash carryover still requires the fans to be washed on an intermittent basis but the cleaning frequency is being steadily reduced.

The inlet and outlet dampers of the induced-draft fans have also suffered erosion from fly ash carryover. Metal on the dampers has been rewelded or replaced several times. When deposits have interferred with operation, the dampers have bound and pins have sheared as a result. Seal air has been provided to keep the bearings clean.

3. Limestone Conveying System: Limestone rocks and coal are stored in two separate piles adjacent to each other. Both materials are transported to the boiler by a single conveying system, used on a time sharing basis. Problems created by this arrangement are chiefly logistic, except delivery chutes are clogged by the fines of proper

size 3/4" x 0" necessitating the delivery of 2" x 1/8". This creates other problems because larger steel balls must be used in the mills; consequently limestone slurry with improper fineness occurs and a greater challenge to good chemistry results. The addition of a separate limestone delivery system this fall will alleviate these problems.

4.3 PROCESS MODIFICATIONS FOR FUTURE INSTALLATIONS

B&W personnel who designed the wet limestone FGD system at the La Cygne power plant, are generally satisfied with the modifications that have been made to remedy operational problems. Present plans call for the use of more reheater tube bundles to raise the temperature of cleaned gas to the desired level thereby eliminating the hot combustion air bleed.

Considerable variations in operability, in terms of pH control, have been observed, with the use of various grades of limestone. The key factor or ingredient making some limestones more suitable than others has not yet been completely identified, but maintaining specified parameters definitely has minimized the problems of chemistry.

APPENDIX A

PLANT SURVEY FORMS

PLANT SURVEY FORM[a]

NON-REGENERABLE FGD PROCESSES

A. COMPANY AND PLANT INFORMATION

1.	COMPANY NAME	Kansas City Power and Light
2.	MAIN OFFICE	Kansas City, Mo.
3.	PLANT MANAGER	Charles Rvan
4.	FGD MANAGER	Cliff McDaniel
5.	PLANT LOCATION	La Cygne, Kansas
6.	PERSON TO CONTACT FOR FURTHER INFORMATION	Terry Eaton
7.	POSITION	Results Superintendent
8.	TELEPHONE NUMBER	
9.	DATE INFORMATION GATHERED	6/5/74
10.	PARTICIPANTS IN MEETING	AFFILIATION
	Terry Eaton	KCPL (Results Supdt.)
	Cliff McDaniel	KCPL (FGD Plant Supdt.)
	Wade Ponder	EPA
	John Busik	EPA
	Tim Devitt	PEDCo Environmental
	Larry Yerino	PEDCo Environmental
	Fouad Zada	PEDCo Environmental
	Dallas Wade (part-time)	B&W

[a]These data were obtained on June 5, 1974. Some of the data have been updated in the text of the report.

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B. PLANT DATA. (APPLIES TO ALL BOILERS AT THE PLANT).

	BOILER NO.				
	1				
CAPACITY, MW (net)	820				
SERVICE (BASE, PEAK)	Base				
FGD SYSTEM USED	Yes				

C. BOILER DATA. COMPLETE SECTIONS (C) THROUGH (R) FOR EACH BOILER HAVING AN FGD SYSTEM.

1. BOILER IDENTIFICATION NO. La Cygne 1
2. MAXIMUM CONTINUOUS HEAT INPUT 7676 MM BTU/HR
3. MAXIMUM CONTINUOUS GENERATING CAPACITY 820 MW (net)
4. MAXIMUM CONTINUOUS FLUE GAS RATE, 2,765,000 ACFM @ 285°F
5. BOILER MANUFACTURER B & W
6. YEAR BOILER PLACED IN SERVICE February 1973
7. BOILER SERVICE (BASE LOAD, PEAK, ETC.) Base
8. STACK HEIGHT 700 ft.
9. BOILER OPERATION HOURS/YEAR (1974) 4578
10. BOILER CAPACITY FACTOR * 23%
11. RATIO OF FLY ASH/BOTTOM ASH 30/70

* DEFINED AS: $\frac{\text{Kwh GENERATED IN YEAR}}{\text{MAX. CONT. GENERATED CAPACITY IN KW x 8760 HR/YR}}$

D. FUEL DATA

1. COAL ANALYSIS (as received)

	MAX.	MIN.	AVG.
GHV (BTU/LB.)	--		9500
S %	--		5.3
ASH %			25

2. FUEL OIL ANALYSIS (exclude start-up fuel)

GRADE	--	--	--
S %	--	--	--
ASH %	--	--	--

E. ATMOSPHERIC EMISSIONS

1. APPLICABLE EMISSION REGULATIONS

	PARTICULATES	SO_2
a) CURRENT REQUIREMENTS		
AQCR PRIORITY CLASSIFICATION	III	
REGULATION & SECTION NO.	28-19-31 Kansas Air Pollution Emission Control Regulation	
MAX. ALLOWABLE EMISSIONS LBS/MM BTU	0.128	
b) FUTURE REQUIREMENTS, COMPLIANCE DATE		
REGULATION & SECTION NO.		
MAXIMUM ALLOWABLE EMISSIONS LBS/MM BTU		

2. PLANT PROGRAM FOR PARTICULATES COMPLIANCE

Compliance through refinements of existing FGD system.

3. PLANT PROGRAM FOR SO_2 COMPLIANCE

Compliance through refinements of existing FGD systems.

F. PARTICULATE REMOVAL

1. TYPE	MECH.	E.S.P.	FGD
MANUFACTURER	--	--	Wet-Limestone
EFFICIENCY: DESIGN/ACTUAL	--	--	B & W
MAX. EMISSION RATE* LB/HR			.1# per 1000# gas
GR/SCF			
LB/MMBTU			

DESIGN BASIS, SULFUR CONTENT _____

G. DESULFURIZATION SYSTEM DATA

1. PROCESS NAME B & W Wet Limestone
2. LICENSOR/DESIGNER NAME: B & W
   ADDRESS: Barberton, Ohio
   PERSON TO CONTACT: Carl Hamilton
   TELEPHONE NO.: (216) 753-4511
3. ARCHITECTURAL/ENGINEERS, NAME: Same
   ADDRESS: _____
   PERSON TO CONTACT: _____
   TELEPHONE NO.: _____
4. PROJECT CONSTRUCTION SCHEDULE: DATE

   a) DATE OF PREPARATION OF BIDS SPECS. _____
   b) DATE OF REQUEST FOR BIDS _____
   c) DATE OF CONTRACT AWARD _____
   d) DATE ON SITE CONSTRUCTION BEGAN April 1969
   e) DATE ON SITE CONSTRUCTION COMPLETED _____
   f) DATE OF INITIAL STARTUP Feb. 1973
   g) DATE OF COMPLETION OF SHAKEDOWN June 1, 1973

*At Max. Continuous Capacity

5. LIST MAJOR DELAYS IN CONSTRUCTION SCHEDULE AND CAUSES:

Construction was on schedule

6. NUMBER OF SO_2 SCRUBBER TRAINS USED 7

7. DESIGN THROUGHPUT PER TRAIN, ACFM @ 122 °F 340,000

8. DRAWINGS: 1) PROCESS FLOW DIAGRAM AND MATERIAL BALANCE
2) EQUIPMENT LAYOUT

H. SO_2 SCRUBBING AGENT

1. TYPE Limestone

2. SOURCES OF SUPPLY Local - 2 miles

3. CHEMICAL COMPOSITION (for each source)

SILICATES 5 to 7

SILICA

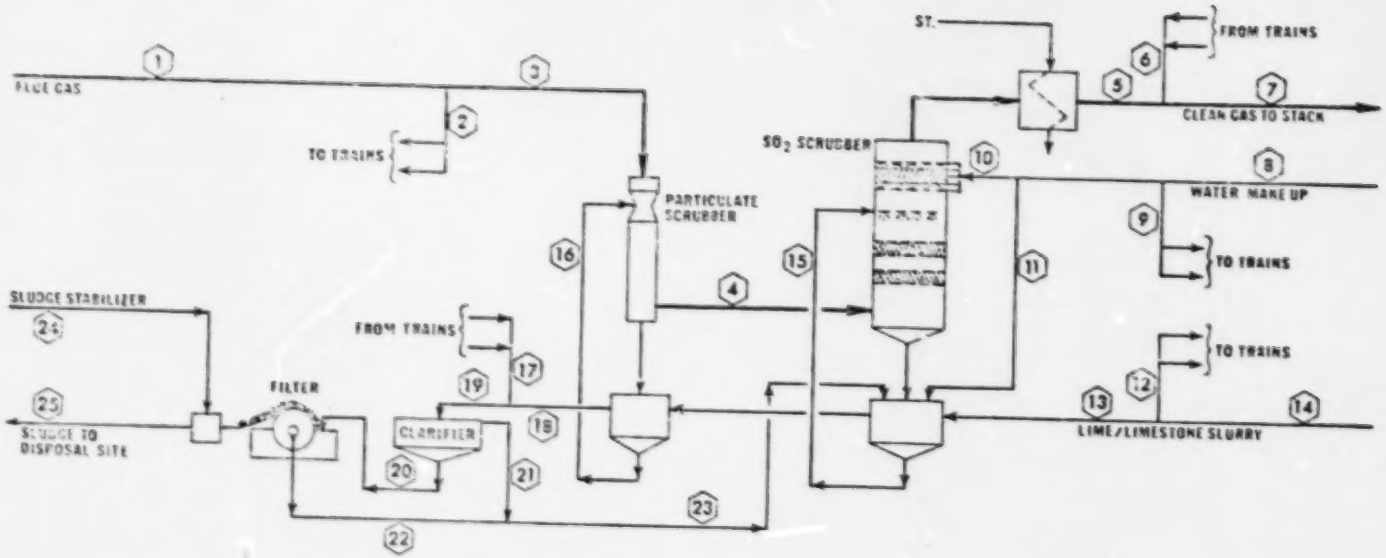
CALCIUM CARBONATE 85% min to 93%

MAGNESIUM CARBONATE 2.5% max

4. EXCESS SCRUBBING AGENT USED ABOVE STOICHIOMETRIC REQUIREMENTS 1.7

5. MAKE-UP WATER POINT OF ADDITION Wet ball mill - Recirculation tank

6. MAKE-UP ALKALI POINT OF ADDITION Slurry into Recirculation tank of each module



STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13
RATE, lb/hr													
ACFM													
GPM				346,000	420,000								
PARTICULATES, lb/hr	60,000												
SO_2, lb/hr	80,000												260
TEMPERATURE, °F	284°F												
TOTAL SOLIDS, %													
SPECIFIC GRAVITY													
													20

STREAM NO	14	15	16	17	18	19	20	21	22	23	24	25	26
RATE, lb/hr													
ACFM													
GPM	1750	9000	4000		800								
PARTICULATES, lb/hr													
SO_2, lb/hr													
TEMPERATURE, °F													
TOTAL SOLIDS, %	20	14			14								
SPECIFIC GRAVITY													

1. Representative flow rates based on operating data at maximum continuous load

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J. SCRUBBER TRAIN SPECIFICATIONS

1. SCRUBBER NO. 1 (a)

TYPE (TOWER/VENTURI)	Venturi
LIQUID/GAS RATIO, G/MCF @ 122 °F	18 Design/12 Actual
GAS VELOCITY THROUGH SCRUBBER, FT/SEC	130
MATERIAL OF CONSTRUCTION	316L SS w/2" Kaocrete ceramic Cladding to midpoint on sump
TYPE OF LINING	None
INTERNALS:	
TYPE (FLOATING BED, MARBLE BED, ETC.)	--
NUMBER OF STAGES	--
TYPE AND SIZE OF PACKING MATERIAL	--
PACKING THICKNESS PER STAGE (b)	
MATERIAL OF CONSTRUCTION, PACKING:	--
SUPPORTS:	--

2. SCRUBBER NO. 2 (a)

TYPE (TOWER/VENTURI)	Tower
LIQUID/GAS RATIO, G/MCF @ 121 °F	26.5
GAS VELOCITY THROUGH SCRUBBER, FT/SEC	8.4
MATERIAL OF CONSTRUCTION **	316L SS
TYPE OF LINING	None
INTERNALS:	
TYPE (FLOATING BED, MARBLE BED, ETC.)	30% air pass 1-3/8" holes Perforated tray
NUMBER OF STAGES	All modules: two trays, one water wash tray
TYPE AND SIZE OF PACKING MATERIAL	--

a) Scrubber No. 1 is the scrubber that the flue gases first enter. Scrubber 2 (if applicable) follows Scrubber No. 1.

PACKING THICKNESS PER STAGE --

MATERIAL OF CONSTRUCTION, --

SUPPORTS: --

3. CLEAR WATER TRAY (AT TOP OF SCRUBBER)

TYPE 11 gauge 1-3/8" holes 316LSS

L/G RATIO --

SOURCE OF WATER --

4. DEMISTER

TYPE (CHEVRON, ETC.) Chevron

NUMBER OF PASSES (STAGES) Two

SPACE BETWEEN VANES 2"

ANGLE OF VANES

TOTAL DEPTH OF DEMISTER 10-5/16"

DIAMETER OF DEMISTER

DISTANCE BETWEEN TOP OF PACKING AND BOTTOM OF DEMISTER

POSITION (HORIZONTAL, VERTICAL) Horizontal

MATERIAL OF CONSTRUCTION Fiberglass (Hetron 197)

METHOD OF CLEANING Underspray and overspray water lanes

SOURCE OF WATER AND PRESSURE Recirc. Pond Water

FLOW RATE DURING CLEANINGS, GPM Overspray: 2100 gpm
Underspray: 130 gpm

FREQUENCY AND DURATION OF CLEANING Overspray: 1 min. per 8 hr.
Underspray: continuous

REMARKS

5. REHEATER 6 modules: Indirect steam & suppl. direct heat

TYPE (DIRECT, INDIRECT) 1 module: Indirect steam

Water leakage through mechanical seals of venturi and tower circulation pumps is about 10 gpm per pump.

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DUTY, MMBTU/HR _____

HEAT TRANSFER SURFACE AREA SQ.FT _____

TEMPERATURE OF GAS: IN 121°F OUT 190°F

HEATING MEDIUM SOURCE Steam & Suppl. Hot Air

TEMPERATURE & PRESSURE 690°F - 140 psig

FLOW RATE 7600 LB/HR

REHEATER TUBES, TYPE AND MATERIAL OF CONSTRUCTION 304 SS (original) 316L SS (Replacement)

REHEATER LOCATION WITH RESPECT TO DEMISTER Immediately on top of demister

METHOD OF CLEANING Steam soot blowers, IK

FREQUENCY AND DURATION OF CLEANING Once/4 hrs - 5 min.

FLOW RATE OF CLEANING MEDIUM _____ LB/HR

REMARKS _____

6. SCRUBBER TRAIN PRESSURE DROP DATA

	INCHES OF WATER
PARTICULATE SCRUBBER	6-9
SO_2 SCRUBBER	6
CLEAR WATER TRAY	1.2
DEMISTER	0.2
REHEATER	3.6
DUCTWORK	4
TOTAL FGD SYSTEM	21-24

7. FRESH WATER MAKE UP FLOW RATES AND POINTS OF ADDITION

TO: DEMISTER Intermittent - 2100 gpm (8 hours)
130 gpm - continuous

QUENCH CHAMBER 37 gpm throat flush

ALKALI SLURRYING 200 per module + 177 make-up

PUMP SEALS 10 gpm x 2 (module)

OTHER _____

TOTAL _____

FRESH WATER ADDED PER MOLE OF SULFUR REMOVED _____

8. BYPASS SYSTEM

CAN FLUE GAS BE BYPASSED AROUND FGD SYSTEMS No

GAS LEAKAGE THROUGH BYPASS VALVE, ACFM --

K. SLURRY DATA

	pH	% Solids	Capacity (gal)	Hold up time
LIME/LIMESTONE SLURRY MAKEUP TANK	7.5	20		
PARTICULATE SCRUBBER EFFLUENT HOLD TANK (a). One Common Tank	5.5 -6.0	8-10		
SO_2 SCRUBBER EFFLUENT HOLD TANK (a)		--	--	--

(a) Carbon steel, rubber-lined

L. LIMESTONE MILLING AND CALCINING FACILITIES: INDICATE BOILERS SERVED BY THIS SYSTEM.

TYPE OF MILL (WET CYCLONE, ETC.) Wet ball mill

NUMBER OF MILLS two

CAPACITY PER MILL 108 T/HR

RAW MATERIAL MESH SIZE 2" x 1/8" (3/4" x 0" - Specs)

PRODUCT MESH SIZE 95% minus 200 mesh

SLURRY CONCENTRATION IN MILL 66%

CALCINING AND/OR SLAKING FACILITIES None

SOURCE OF WATER FOR SLURRY MAKE UP OR SLAKING TANK Recycle from settling pond

M. DISPOSAL OF SPENT LIQUOR

1. SCHEMATICS OF SLUDGE & FLY ASH DISPOSAL METHOD

(IDENTIFY QUANTITIES OR SCHEMATIC) _____

2. CLARIFIERS (THICKENERS)

NUMBER None

DIMENSIONS --

CONCENTRATION OF SOLIDS IN UNDERFLOW --

3. ROTARY VACUUM FILTER

NUMBER OF FILTERS None

CLOTH AREA/FILTER --

CAPACITY _____ TON/HR (WET CAKE)

CONCENTRATION OF SOLIDS IN CAKE --

PRECOAT (TYPE, QUANTITY, THICKNESS) --

REMARKS --

--

--

4. SLUDGE FIXATION

POINT OF ADDITIVES INJECTION None

FIXATION MATERIAL COMPOSITION --

FIXATION PROCESS (NAME) --

FIXATION MATERIAL REQUIREMENT/TONS OF DRY SOLIDS OF SLUDGE

--

ESTIMATED POND LIFE, YRS. 4 years

CONCENTRATION OF SOLIDS IN FIXED SLUDGE 10%

METHOD OF DISPOSAL OF FIXED SLUDGE On site Ponding

INITIAL SOLIDIFICATION TIME OF FIXED SLUDGE --

5. SLUDGE QUANTITY DATA

POND/LANDFILL SIZE REQUIREMENTS, ACRE-FT/YR 400

IS POND/LANDFILL ON OR OFFSITE On site

TYPE OF LINER None

IF OFFSITE, DISTANCE AND COST OF TRANSPORT --

POND/LANDFILL DIMENSIONS AREA IN ACRES 160
DEPTH IN FEET 10 to 12

DISPOSAL PLANS; SHORT AND LONG TERM

Develop market for fly ash fill-gypsum.

Evaluate filling nearby quarry

N. COST DATA

1. TOTAL INSTALLED CAPITAL COST Initially: 32.5 million dollars
projected final cost: 45-50 mill. dollars

2. ANNUALIZED OPERATING COST 1,870,000
1.79 mils/KW hr

3. COST BREAKDOWN

	COST ELEMENTS	INCLUDED IN ABOVE COST ESTIMATE YES	NO	ESTIMATED AMOUNT OR % OF TOTAL INSTALLED CAPITAL COST
A.	CAPITAL COSTS			
	SO_2 SCRUBBER TRAINS	☐	☐	19,310,192
	LIMESTONE MILLING FACILITIES	☐	☐	4,878,598
	SLUDGE TREATMENT & DISPOSAL POND	☐	☐	3,225,289
	SITE IMPROVEMENTS	☐	☐	261,218
	LAND, ROADS, TRACKS, SUBSTATION	☐	☐	82,136
	ENGINEERING COSTS	☐	☐	1,610,000
	CONTRACTORS FEE	☐	☐	1,219,000
	INTEREST ON CAPITAL DURING CONSTRUCTION	☐	☐	4,088,522
B.	ANNUALIZED OPERATING COST			
	FIXED COSTS			
	INTEREST ON CAPITAL	☐	☐	
	DEPRECIATION	☐	☐	10 years
	INSURANCE & TAXES	☐	☐	242,000
	LABOR COST INCLUDING OVERHEAD	☐	☐	
	VARIABLE COSTS			
	RAW MATERIAL	☐	☐	
	UTILITIES	☐	☐	
	MAINTENANCE	☐	☐	

4. COST FACTORS

a. ELECTRICITY _____

b. WATER _____

c. STEAM (OR FUEL FOR REHEATING) _____

d. FIXATION COST _____ $/TON OF DRY SLUDGE

e. RAW MATERIAL PURCHASING COST _____ $/TON OF DRY SLUDGE

f. LABOR: SUPERVISOR _____ HOURS/WEEK _____ WAGE

OPERATOR _____ _____

OPERATOR HELPER _____ _____

MAINTENANCE _____ _____

O. MAJOR PROBLEM AREAS: (CORROSION, PLUGGING, ETC.)

1. SO_2 SCRUBBER, CIRCULATION TANK AND PUMPS.

a. PROBLEM/SOLUTION _____

2. DEMISTER

PROBLEM/SOLUTION 1. SO_4 scale build up; added 50% clear water to recirculated pond water (probably can get by with less fresh water). Z-shape demisters are 1/8" thick.

3. REHEATER

PROBLEM/SOLUTION 304 SS reheater - Cl. Stress corrosion and sulfurous acid. Chlorides are from pond water. Replacing with 316L SS.

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4. VENTURI SCRUBBER, CIRCULATION TANKS AND PUMPS

PROBLEM/SOLUTION_____

5. I.D. BOOSTER FAN AND DUCT WORK

PROBLEM/SOLUTION_____

6. LIMESTONE MILLING SYSTEM OR LIME SLAKING

PROBLEM/SOLUTION_____

7. SLUDGE TREATMENT AND DISPOSAL

PROBLEM/SOLUTION_____

8. MISCELLANEOUS AREA INCLUDING BYPASS SYSTEM

PROBLEM/SOLUTION

P. DESCRIBE FACTORS WHICH MAY NOT MAKE THIS A REPRESENTATIVE INSTALLATION

Q. DESCRIBE METHODS OF SCRUBBER CONTROL UNDER FLUCTUATING LOAD. IDENTIFY PROBLEMS WITH THIS METHOD AND SOLUTIONS. IDENTIFY METHOD OF pH CONTROL AND LOCATION OF pH PROBES.

Automatic pH, SO_2 index and gas flow to proportion feed slurry.

R. COMPUTATION OF FGD SYSTEM AVAILABILITY FACTOR

BOILER RATING OR MAXIMUM CONTINUOUS CAPACITY, MW _____

PERIOD MONTH/YEAR	FLUE GAS DESULFURIZATION MODULES							
	MODULE A		MODULE B		MODULE C		MODULE D	
	DOWN DUE TO		DOWN DUE TO		DOWN DUE TO		DOWN DUE TO	
	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)

Availability factor computation:

1. Divide boiler capacity by the number of modules and obtain MW/module = χ
2. Multiply boiler capacity by number of hours during period = a
3. Add all down times due to module trouble for all modules during period = b
4. Add all down times due to boiler trouble or reduction in electricity demand for all modules during period = c
5. Availability factor = $\frac{[a - \chi\ (b + c)]100}{a - \chi\ c}$ = %

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APPENDIX B

PLANT PHOTOGRAPHS

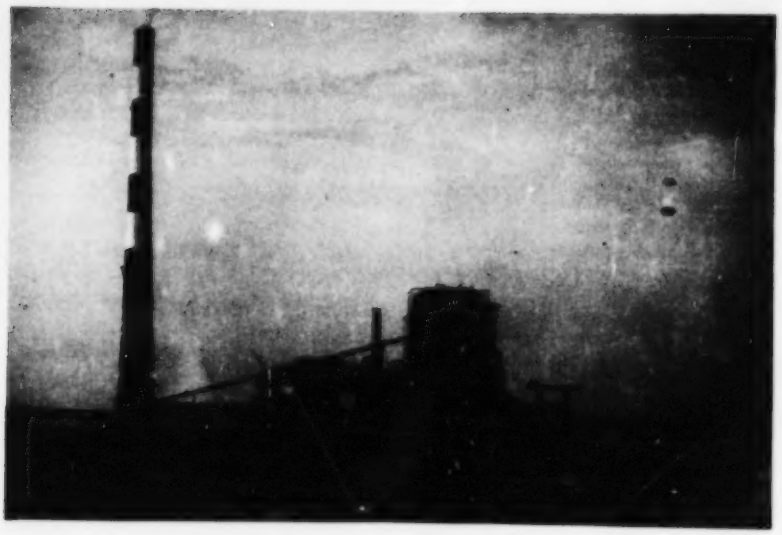

Photo No. 1 General view of the La Cygne Power Station. The building, which houses the flue gas desulfurization modules, is shown between the boiler structure and the stack.

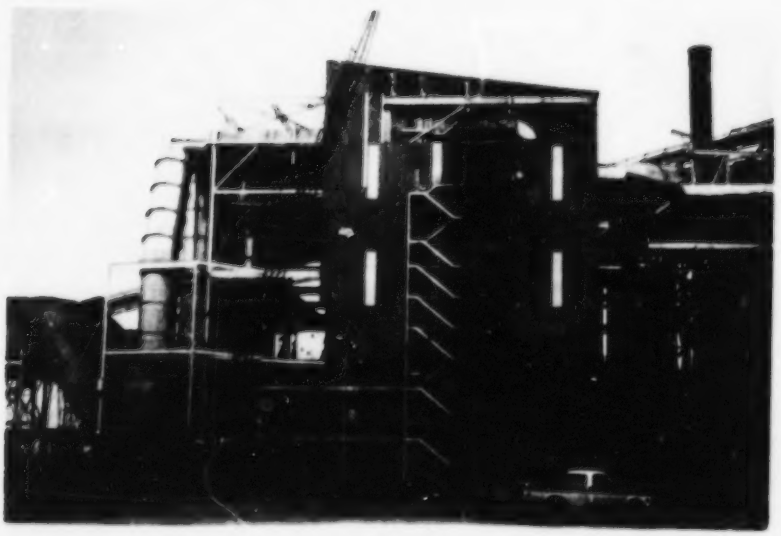

Photo No. 2 Close-up view of the FGD building showing the flue gas ductwork to and from the building.

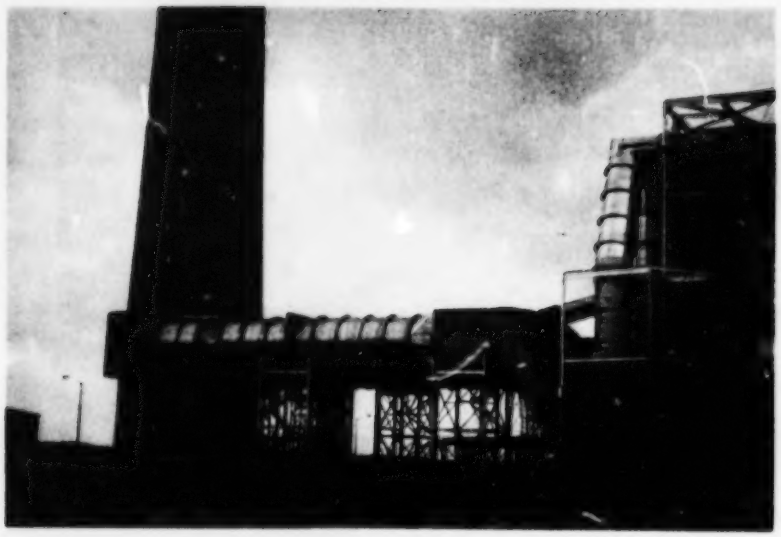

Photo No. 3 Close-up view of the high pressure (60" W.G.) I.D. fans which are the prime movers of gas through both the boiler and the FGD system.

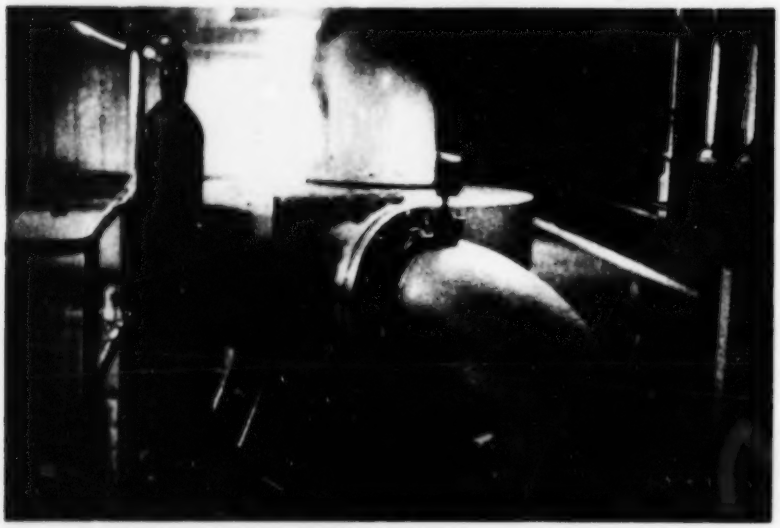

Photo No. 4 Picture of one of the seven Hydroclones (liquid cyclones) inside the FGD building. The function of these units is to remove scale particles from the recirculated slurry to the venturi scrubbers.

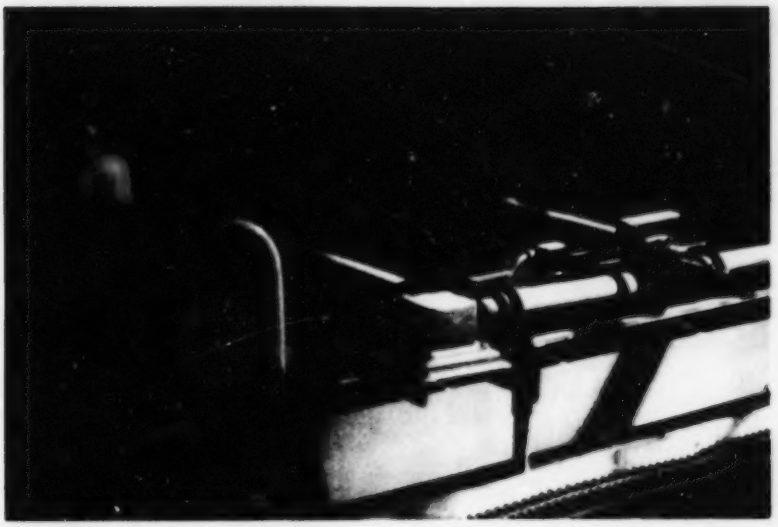

Photo No. 5 Close-up view of a venturi scrubber throat, showing the motor operated mechanism for varying the gap at the throat.

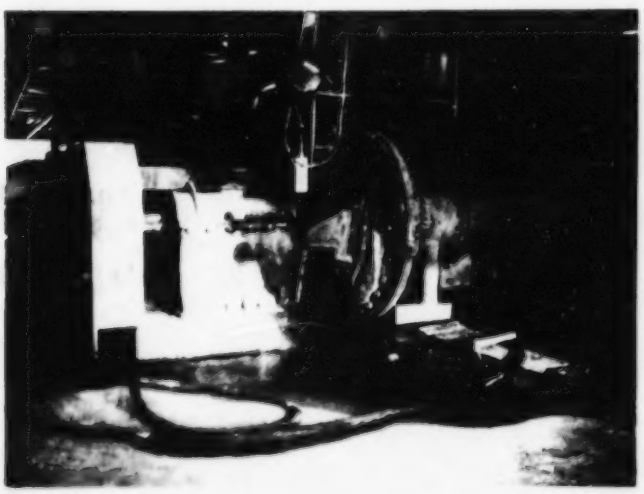

Photo No. 6 View of the battery of recirculation pumps which serve the venturi scrubbers. The SO_2 scrubber pumps are similar in design to these.

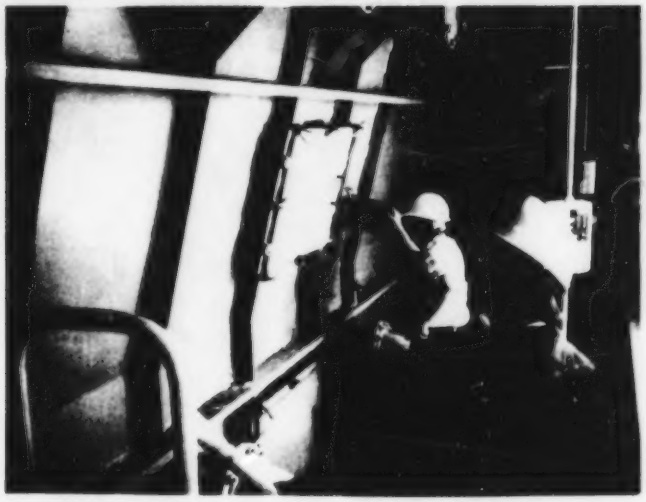

Photo No. 7 Partial view of one of the SO_2 scrubber towers taken at the demister level.

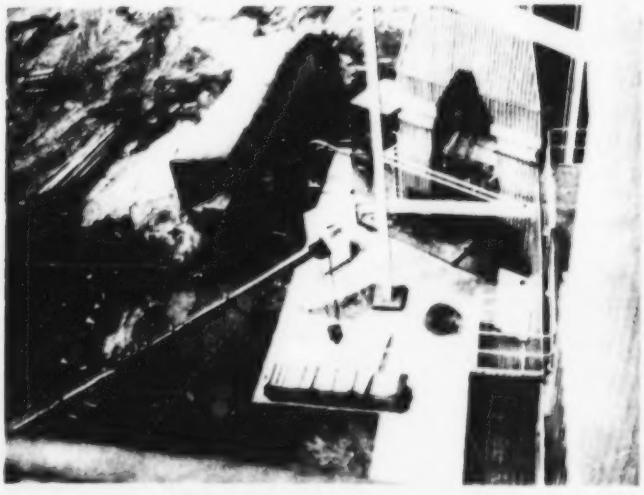

Photo No. 8 Picture taken during the arrival of some of the new 316L SS reheater bundles shown here being unloaded. One of the high pressure I.D. fans is shown in the upper right corner.

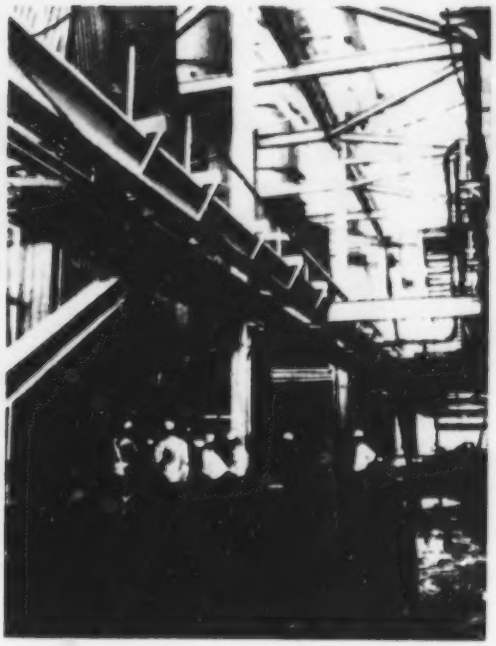

Photo No. 9 View of the I.D. fans area indicating the large size of these units. One fan is shown here being taken down for repair.

Photo No. 10 View of the limestone rock storage piles which are located near the coal storage area. The limestone is intermittently transported to the mill using the coal conveying system.

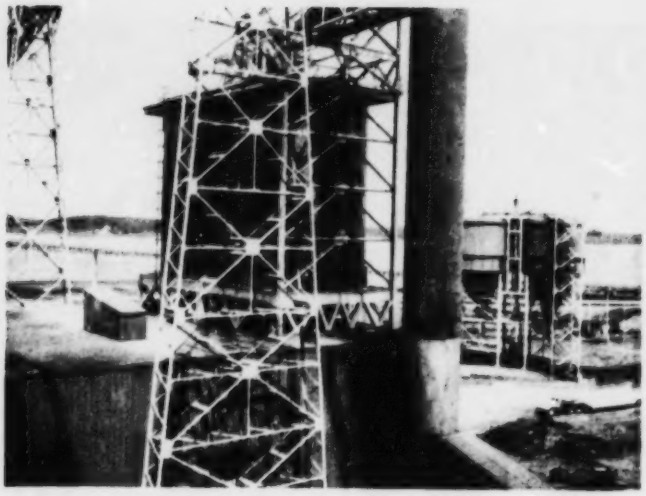

Photo No. 11 View of the twin limestone storage silos located on top of the limestone milling building. The small chimney of the three oil fired auxiliary boilers is shown to the right of the silos.

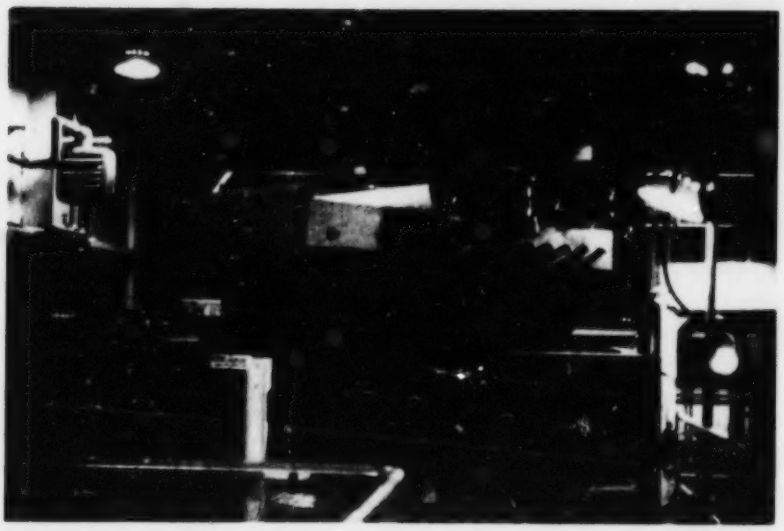

Photo No. 12 View inside the limestone milling building showing the limestone feeding and weighing equipment. The cone shown is the bottom of one of the two limestone storage silos.

Photo No. 13 View of one of the two limestone ball mills showing the feed chute to the rotating mill drum.

Photo No. 14 View of the discharge end of one of the two limestone mills. These mills (each rated at 110 ton/hr capacity) are driven by 2000 hp motors.

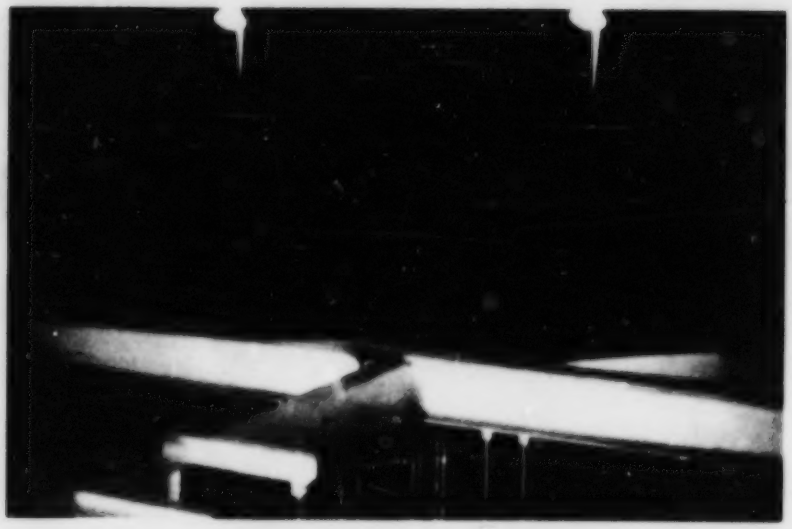

Photo No. 15 View near the top of one of the two limestone slurry storage holdings tanks. These tanks are located inside the limestone milling building, a short distance from the mill.

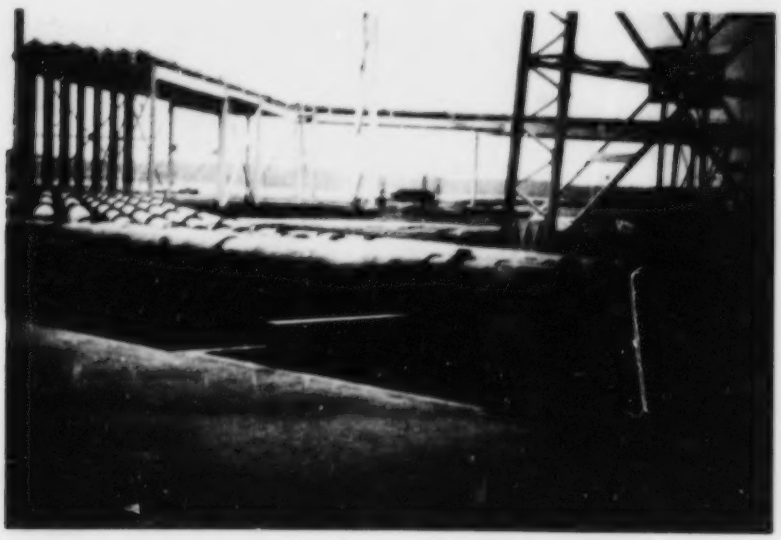

Photo No. 16 View of the pipes, some of which carry the ash and limestone sludge from the FGD system to the pond, while the others transport back the recycled pond water as well as fresh make-up water from the lake.

Photo No. 17 Partial view of the 160 acre ash-limestone sludge pond. The coal storage pile is shown in the background.

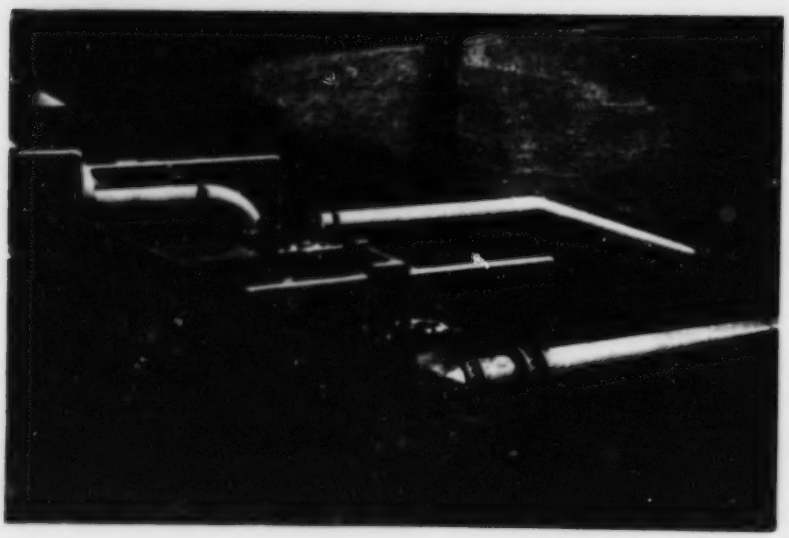

Photo No. 18 This pumping station, located near the pond (not shown), provides the energy for recycling the clarified pond water as well as pumping fresh water from the lake canal (partly shown).

Photo No. 19 General view of the La Cygne Power Station taken near the water pumping station.

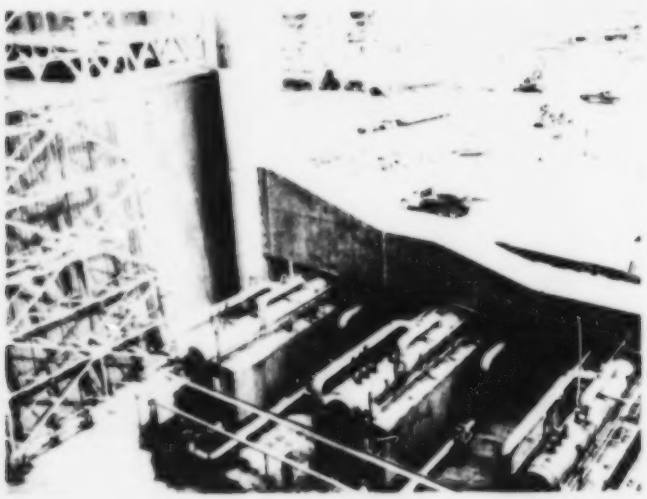

Photo No. 20 View of the three oil fired auxiliary boilers at the La Cygne Power Station. They are primarily used to start up the large coal fired boilers.

Photo No. 21 View of the foundation of the second boiler under construction.

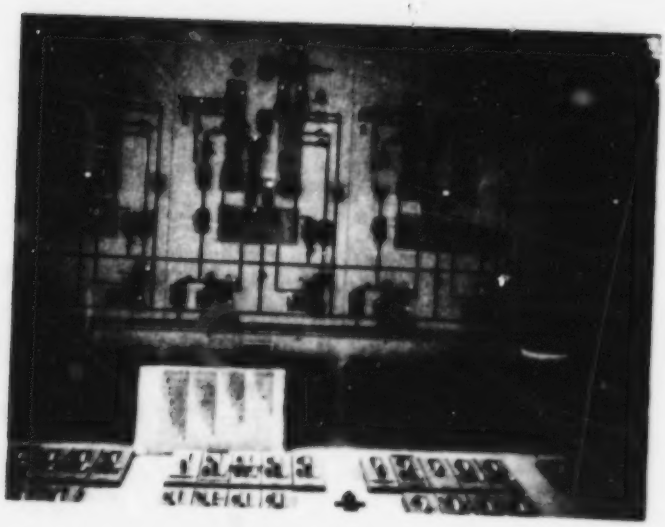

Photo No. 22 Partial view of the schematic instrument control panel which is located in the main boiler control room. There are seven scrubber modules identified from A to G.

APPENDIX C

PLANT OPERATING RECORD

Availability Factor

for

The FGD System on La Cygne No. 1

The following calculations of availability factor are based on record of outages data presented in a paper by A. E. Schnake. The paper, titled "Start-Up of the La Cygne Unit No. 1", was presented at the 1974 Engineering Conference of the Missouri Valley Electric Association at Kansas City, Missouri on April 17, 1974.

Period covered: February 23, 1973 to February 16, 1974.

Time during period: 8616 hours

Time scrubbers were down: 3887 hours approx.

$$\text{Availability factor} = \frac{(8616 - 3887 - 548) \times 100}{8616 - 3887} = 88\%$$

It should be noted that this availability factor is conservative, since it assumes that all seven scrubber modules were down, which is not true. Therefore the availability of the FGD is higher than 88 percent. Also it is assumed that during the periods when the boiler was down, the scrubber modules were available if needed.

Note that this availability factor applies only to the above stated period when the boiler was down because of numerous problems, and the modules were accessible for thorough cleaning and repairs after short operating intervals. As down times of the boiler become less frequent and shorter, down time of the scrubber is likely to increase and the availability of the FGD system will decrease.

1974 ENGINEERING CONFERENCE
POWER GENERATION COMMITTEE
Missouri Valley Electric Association
Kansas City, Missouri – April 17, 1974

START- UP of LA CYGNE UNIT No.1

KANSAS CITY POWER & LIGHT COMPANY and
KANSAS GAS AND ELECTRIC COMPANY

Presented By – A. E. Schnake Maintenance Engineer
Kansas City Power & Light Company

DESCRIPTION

La Cygne Unit No. 1 is located about 55 miles south of downtown Kansas City and two miles east of Highway U.S. 69. The plant is jointly owned equally by Kansas City Power & Light and Kansas Gas & Electric Company. The plant is manned exclusively by KCP&L employees with output shared equally by the two companies.

Construction was started in April 1969, reaching the halfway point in October of 1971, with a construction force of over 900 men. Unit No. 1 was nearing completion when the boiler was first fired on December 26, 1972, and construction was considered complete when the unit was declared commercial on June 1, 1973.

An earthfill dam almost 7,000 feet long was constructed to form a lake for cooling. The lake covers 2,600 acres at normal operating level with a volume of 40,000 acre-feet. The lake level is controlled with two radial gates that are 44 feet wide. Make-up water to the lake can be pumped with two 20,000 gpm pumps from the Marais des Cygnes River through a 48 inch underground pipe almost 5 miles long to the lake. The pumps were used some in the initial filling of the lake. Rain and watershed have kept the lake at operating level since January, 1973.

The plant site was originally sized for two 800 mw generators. However, construction has been started on Unit No. 2 and it will be approximately 600 mw. The plant was designed for black start capability. A 2200 kw, 480 volt diesel generator will provide power to light off an auxiliary boiler. The auxiliary steam powers a 22 mw, 6,900 volt auxiliary turbine generator. The auxiliary turbine generator will then provide power for the auxiliaries to light off the No. 1 boiler and roll the generator.

A General Electric monitoring and information computer supplies information to the following equipment located in the control room. Alarms are shown on an alarm video (television screen) and typed out on an alarm typewriter. Desired information can be displayed on an operators video, recorded on three 4-point trend recorders or printed out on a trend typewriter. A periodic log, which summarizes the operation of the boiler, turbine generator and principal auxiliaries is printed out hourly on a log typewriter.

Coal is delivered to the mine mouth plant with off-the-road 120 ton trucks from a strip mine operated by Pittsburg & Midway Coal Company. 30 in.X 0 R.O.M. size coal is conveyed from the receiving hoppers at a rate of 2,000 tons per hour to two rotary breakers and reduced to 3 in. X 0 size. The coal then passes to the primary crushers and is reduced to 3/4 in. X 0 size. It continues on to be stacked out in the storage area with the stacker-reclaimer or a maximum of 1200 TPH may bypass the stacker-reclaimer going on to the secondary crushers. Live storage area for the stacker-reclaimer is 198,000 tons of coal and 64,000 tons of limestone. The secondary crushers reduce the coal size from 3/4 in. X 0 to 1/4 in. X 0. The coal then continues on to the bunkers sized for 10 hours with the unit at full load.

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Startup of the main boiler requires steam to drive the boiler feed pump turbine and seal steam. Three auxiliary boilers rated at 200 psig and 200,000 lbs. per hr flow provide the steam for startup. They were supplied by Erie City with Forney fuel safety controls.

The boiler is a supercritical once-through balanced draft Babcock & Wilcox boiler with Bailey controls. Rating is 6,200,000 pounds per hour, 1,010°F, 3,825 psig at superheat outlet and 1,010°F at the reheater outlet. Eighteen positive pressure cyclones (9 on the front and 9 on the rear) fed with Stock Equipment gravimetric feeders and controlled with a Bailey 660 System provide fire for the boiler. A Bailey 820 System controls the rest of the boiler functions. Firing rate and attemperator sprays control superheat temperature. Reheat temperature is controlled with gas recirculation and attemperator sprays. Feed water flow is provided with 2 half-capacity Pacific boiler feed pumps driven with Westinghouse turbines. Boiler cleaning is done with Diamond Power (IK) sootblowers and (IR) wallblowers. Boiler air flow is provided with three one-third capacity forced draft fans equipped with forced lubrication system and supplied by Green Fuel Economizer Company. Six one-sixth capacity induced draft fans, supplied by Sturtevant control the furnace pressure. The ID and FD fans are powered with 7,000 horsepower Westinghouse motors. Boiler air is heated with an air preheater coil heating system before passing through a Ljungstrom horizontal air preheater.

United Conveyor supplied the ash handling equipment. Bottom ash flows from the boiler as hot slag and is quenched in two slag tanks. Each slag tank has 2 ash lines to convey the ash to a dewatering bin or to the ashpond. Economizer ash is drawn from five hoppers with vacuum hydroveyors and conveyed to the slag tanks where it is disposed of with the bottom ash. Fly ash is removed with the Air Quality Control (AQC) System.

Boiler gas is cleaned with 7 B&W limestone slurry scrubbers. The original intent was to have seven one-seventh capacity modules, However, modifications have derated the modules. Each module has 2 sections, a venturi section for fly ash removal and an absorber section for sulfur dioxide removal.

A milling system is required to make limestone slurry for the scrubbers. Two Koppers limestone ball mills are designed to reduce the rock from 3/4 in. x 0 to slurry at a rate of 110 tons per hour. The slurry then passes through Krebs cyclone classifiers and is either rejected back to the mill or passed on to the slurry storage tanks.

The turbine-generator was supplied by Westinghouse with an electro-hydraulic control. The hydrogen cooled generator is guaranteed to 800 mw and will generate 870 mw at .90 power factor with 5# overpressure and 75 psig hydrogen pressure. The hydrogen cooled exciter consists of a permanent magnet generator, an a-c generator, and a rectifier assembly mounted on a common shaft. The turbine is a four-casing tandem-compound quadruple exhaust condensing reheat turbine. Simply speaking, this is a double-flow high pressure turbine, a double-flow intermediate pressure turbine, and two double-flow

low pressure turbines, all connected in series to turn the generator and exciter at 3600 RPM. The turbine valves are operated with high pressure fire resistant fluid (1600 to 1900 psig) supplied from the electro-hydraulic control system.

The condenser, supplied by Southwestern Engineering Company, is a single pass unit with 1" stainless steel tubes. Three circulating water pumps, rated at 166,000 gpm, supply cooling water for the condenser. The pumps are driven with Westinghouse synchronous motors.

Lake water is cleaned up with a Belco water treatment plant to provide make up for the boiler. A clarator and sand filters clean water up to a turbidity of 2 ppm at a rate of 600 gpm. The water is then passed through carbon filters to remove chlorine before demineralizing. The 3-bed make up demineralizer with cation, anion, and mixed bed is the final step in preparing boiler make up.

Condensate is passed through a mixed bed polishing demineralizer in its flow to the boiler. The condensate polishing system has 4 high flow polishing demineralizers and a separate regeneration system with cation regeneration tank, anion regeneration tank, and resin storage tank.

START-UP OPERATIONS

The start-up operations of La Cygne No. 1 started during the month of January 1972 when the plant staff was brought up to 9 operators and 9 supervisory personnel. One of the 345,000 volt transmission lines to the plant was already energized. So it was possible for the start-up personnel to energize the standby transformer, some 6,900 volt auxiliary busses, a few of the 480 volt power centers and some 480 volt motor control centers. The busses were energized to check out supply and tie breaker interlocks and for bumping some of the small motors for rotation. However, it was necessary to deenergize the equipment every night since the operators would not be working shifts till the end of February.

The month of February saw more activity with many more motors being bumped. The instrument air compressor was placed in service and technicians were preparing the instrumentation in the water treatment plant for service. The power line from our substation to the coal company was also placed in service.

The operators began working shifts in March and start-up operations continued on a 24-hour basis. The primary water treatment equipment was placed in service allowing us to make enough water to start flushing some of the piping systems. The intake equipment was being checked out and placed in service. The circulating water pumps were bumped for rotation but starting problems would keep 2 of the 3 pumps unavailable till October.

April saw many more lines getting flushed and the bearing cooling water system was placed in service. The make-up demineralizer was placed in service to fill the condensate storage tanks in preparation for a boiler hydro.

The boiler was hydrostatically tested to 6300 psig in May. The stacker/reclaimer was also being checked out to receive coal. The feedwater and boiler cycle piping was complete by June and temporary piping was installed to prepare for a clearwater flush and chemical cleaning of the boiler and preboiler cycle.

The local union started a 23-day strike on the 1st of July and it was necessary to transfer most of the supervisory personnel to other plants to maintain operations. However, the few that remained were able to check rotation of FD fans and get the main turbine oil flush started.

The chemical cleaning and clearwater flush of the preboiler and boiler cycle was completed in August. The main turbine and boiler feed pump turbine hot oil flushes were also completed. Two of the auxiliary boilers were fired up and made available for service.

All six ID fans were run and balanced in September. Plans were made

to pull a vacuum on the condenser, but the vacuum pump bound up mechanically after running only a short time. The first phase of the coal handling system was operational and we started receiving coal.

The auxiliary boilers were used to provide steam for steam blowing of the auxiliary steam piping in October. The main boiler piping was air blown instead of steam blown to save time. The superheat section required 35 air blows and the reheat section of the boiler was satisfactory after 17 blows. The blow would start when air pressure reached 300 psig and would stop at about zero psig. The vacuum pumps were repaired and placed in service and we were able to pull vacuum. The starting problems were cleared up on the circulating water pumps and they were made available for service.

November was a busy month and the operating force had increased from the original 2 men per shift to 7 men per shift. The cold clean up cycle of boiler flow was started, but shutdowns were common due to suction strainers plugging up with dirt and scale. Both boiler feed pumps were run and tested for overspeed trip. ID and FD fans were operated with the air preheater coil system and the air preheaters in service. Cyclone ignitors were checked out along with the coal feeders and the fuel safety system.

The main objective in December was to prepare for the first boiler fire. All available equipment was operated as much as possible to expose start-up problems, and familiarize the operators with the equipment. The boiler was first fired on December 26, 1972 for about 24 hours. An auxiliary boiler had to be taken off because of a split allowing smoke to blow out of the fire box. It was needed to power the boiler feed pump turbine, so was necessary to stop firing the main boiler and have the auxiliary repaired. Other problems also surfaced and it was January 24th before the boiler was fired again. One of the problems that surfaced was the energy crisis, and we experienced difficulty keeping a sufficient supply of light oil.

A steam line to the boiler feed pump turbine was installed during the outage. It allowed steam generated by the main boiler and normally dumped to the condenser to be used to run the B.F.P. turbine. The new steam line allowed us to reduce the auxiliary boiler loading much quicker than originally planned.

The turbine-generator was rolled with steam for the first time on January 25, 1973. The turbine roll history section of this paper starts on this date with the first turbine roll.

During the period of trial operations, we encountered many problems such as; boiler slagging, boiler leaks, balance weight changes on the generator, and I.D. fan problems. This slowed down operations considerably.

Quite often it was necessary to extend the outages to repair equipment that hadn't forced the outage. Some of the problems with the equipment and systems will be covered in the next section.

The start-up of La Cygne No. 1 was not right on schedule but it wasn't far off. Trial operation was originally scheduled to start on October 1, 1972. The first boiler fire on December 26, 1972 was just 12 weeks behind the scheduled date. The unit was scheduled to go commercial on May 1, 1973 and was declared commercial only four weeks late on June 1st. The peak load for the unit was 832 mw and was reached on June 2, 1973. The major factor limiting unit load has been the number of AQC modules available.

EQUIPMENT PROBLEMS

This section of the paper will be devoted to some of the problems that were encountered in the start up of various equipment.

AUXILIARY BOILERS

The "B" auxiliary boiler exploded several months after being placed in service. The boiler was shut down and purged for approximately five minutes. It then exploded about five minutes after shutting down the fan. The source of the fuel for the explosion or how it was ignited is not known at this time. Repair of the boiler was started immediately and it was back in service in about a week. The boiler was fired almost continuously for about five weeks before it had to be shut down again. This was the first time for the rear end of the boiler to burn out. The rear ends of all three boilers have burned out frequently. The boiler skin breaks at the rear corners and the slightly positive furnace pressure allows fire to shoot out and enlarge the holes. The insulation in the rear corners of the boiler was increased on the last repair. This was done to try to stop the holes that appear.

The fuel safety system has given us some problems. The problems usually surface during boiler light off. Houses were built around the boiler front last summer and this seems to have increased the reliability of the system.

CIRCULATING WATER PUMPS

The major problems encountered with the circulating water pumps was that the motor would trip right after starting, usually on "timed overload". The motors were 6,900 volt, 1750 hp, 300 rpm synchronous motors. Apparently the motor reached synchronous speed too fast for the starting circuit to apply the field. The motor would maintain starting current, overspeed and trip off. The field was also generating a high enough voltage to turn off a thyristor. The thyristor had to turn on to apply the field, so a blocking diode was installed. The one motor that would start apparently had a faulty thyristor that the inverse voltage did not turn off. The problem was solved with the installation of the blocking diode. The motors have given us very few problems since that time other than the replacement of diodes and thyristors.

TURBINE GENERATOR

The biggest problem with this unit has been the generator oil seals.

The anti-rotation pins have failed several times, allowing the seal ring to rotate. This breaks the hydrogen seal and allows hydrogen to leak.

The seal oil system has a drain receiving tank with a float valve to control the tank level. The float valve sticks shut occasionally and must be jacked open and adjusted to get it regulating. The valve usually creates a problem when the seal oil to hydrogen differential pressure is increased.

The electro-hydraulic control system has been reliable and provides good control of the turbine-generator. A problem did occur with the EHC system that has not been solved. The problem was that the generator load would increase 150 mw and then decrease 150 mw when either one of the two ID fans were started. The load would eventually level, but if the generator load was less than 450 mw, the unit would trip off. The problem did disappear after some apparently unrelated wiring changes were made.

BOILER

The boiler has had about 32 leaks since the generator was first synchronized. Tube leaks have forced an outage three times. The rest of the leaks didn't force an outage or were found by hydrostatic test when the unit was down for some other reason. The boiler bypass system has forced a few outages due to piping leaks.

COMPUTER

The computer has been in service most of the time. Recently a prefabricated cable was found to have faulty terminations in the connector and was responsible for several outages. Other than this, the computer has been reliable.

PREFABRICATED CABLE

A great deal of the plant wiring was done with prefabricated cables. Many of the cables were too long. The excess length was looped in cable trays and manholes, overloading the trays and crowding the manholes. The connectors are not completely weatherproof and we have had some trouble with the terminations in the connectors.

DC BATTERY CHARGER

The battery charger has been very reliable. A bad card was found one time and it was apparently caused by dirt falling from overhead workers.

ELECTRICAL BREAKERS

The 6900 volt breakers have proven quite reliable. One problem however, that the operators must continually watch for is a linkage rod in the breaker cubicle that operates the auxiliary contacts. It must be aligned with an operating arm on the breaker. The arm occasionally is misaligned when the breaker is rolled into the cubicle.

The auxiliary contact fingers on the 480 volt power center breakers broke on several of the breakers. This problem hasn't appeared since the first few months of operation. One power center breaker did explode, but it apparently was caused by foreign material on the breaker stabs.

The 480 volt motor control center breakers have been very reliable.

BOILER FEED PUMP AND TURBINE

We experienced several problems on the turbine with the speed sensing system. This difficulty was solved by the manufacturer soon after it was placed in service. The turbine has proven very reliable since that time.

The head gaskets on the boiler feed pumps have failed three times and the thrust bearing on "A" pump has failed once. A sudden increase in feedwater flow could have caused the thrust bearing failure. However, the flow didn't increase to an excessive amount and the bearing should not have failed for that reason.

ASH SLUICE PUMPS

The bearings on the ash sluice pumps have failed quite a few times and the rotor has been replaced on all three of the pumps. Both problems seem to be caused by vibration. The manufacturer has recommended changing the suction piping to remove a suction strainer. The bearing failures have also been caused by water leaking from the pump packing into the bearing housing. Mechanical seals have been ordered to correct this problem.

The pump motor has also given us a problem. Two of the motors have failed. One motor had to be rewound because a piece of metal stuck in the rotor and tore up the winding. The other motor had to be completely replaced. A flat spot was worn into the length of the rotor.

VACUUM PUMPS

Both vacuum pumps failed when they were initially started. One ran for a short time and then failed. The other failed the first time it was started. The clearance from the thrust end of the rotor to the

end plate was too much. Something fell between the two surfaces and the rotor bound up. Both the surfaces of the rotor and the end plate had to be remachined. The timing gears were adjusted when the pump was put back together and both pumps have operated since then. One small annoyance is a float valve that controls the level in the seal water reservoir. The valve occasionally sticks open and overflows the reservoir.

INDUCED DRAFT FANS

We have had many problems related to the ID fans and have worked almost continuously on them since they were first balanced in September '72. The fans were initially sensitive to imbalance and it was found that the operating speed was close to the critical speed. However, they were balanced and we attempted to run the fans to get some operating time on them. The fan housing had quite a bit of vibration though, and after finding cracks in the inlet cones, it was decided additional stiffening was needed to strengthen the housing. We proceeded to get more running time on the fans but found the thrust collars on the fan bearing were getting too hot. Thermocouples were originally hooked up to inboard and outboard fan and motor bearing. So, by the time a high temperature was indicated on the inboard fan bearing, the thrust collar had already been wiped. Thermocouples were hooked up to monitor the thrust collar temperature. They indicated thrust temperatures were increasing to the alarm set point of 180°F within a short time after the fan was started. So the inboard bearings were opened up and it was found that the thrust collars were moving. The next thought was that air turbulence in the inlet duct work was causing the rotor to shift from side to side. Several different aerodynamic configurations were tried to eliminate air turbulence. A splitter foil was installed and directional vanes were installed in the duct and in the fan inlet box; but the thrust collar was still getting hot and moving. The next step was to install set screws in the thrust collar and cut oil grooves to keep the thrust face cooler. The collar still moved but it did run cooler.

There was apparently only one way to control the thrust bearing temperature prior to cutting the oil grooves. The temperature would increase very gradually if the fan was loaded to full load motor amps right after it was started. It was possible to vary the fan load some after the oil grooves were cut. It was necessary though to continually monitor bearing temperature and increase the fan load if the temperature increased. The operating guide for the thrust temperature would shut the fan down if, the temperature was increasing gradually and reached 210°F, or any time the temperature went straight up. After many trials, we found we could get to 240°F if the temperature was gradually increasing.

The thrust temperature was eventually controlled by installing forced lubrication systems on all the fans. The lube sets allowed the temperature to drop into a 140°F to 160°F temperature range.

The set screws installed in the thrust collar didn't stop the collar from moving, and the next step was to install pins through the collar into holes drilled into the shaft. It was impossible to make a field installation within specified tolerances and we gave up on installing pins. The next effort at stopping thrust collar movement was to install split back up collars that were designed to give an interference fit. These were successful and were installed on all six ID fans.

The thrust collar movement and high temperature problems were solved but another problem appeared as soon as we started firing the boiler. Slurry was carrying over from the scrubber and coating out on the fans. The buildup would throw the fans out of balance. A high pressure water washer was finally settled on to wash the fans after trying several different methods. The most destructive characteristic of the slurry was erosion to the fan blades. A blade was discovered almost torn in half so all the blades were magnafluxed. The magnaflux revealed several cracks and it became apparent the blades needed to be reinforced. Testing indicated that a plate added across the leading edge of each blade would allow the blades to withstand the stresses they were being subjected to. So each fan blade on all fans was modified after being checked for cracks.

The fans' sensitivity to imbalance was complicated even more by the slurry eroding the fan blades. The leading edge was now protected but the trailing edge and the rest of the blade was still susceptible to erosion. The blades slowly eroded and it was necessary to have the fans rebalanced periodically. The blades on "C" ID fan were eroded to a knife edge thickness and the fan was removed from service with less than a year of service. A new rotor, quite different from the original one, was installed. The shaft size was increased from 20 to 24 inches in diameter and the weight of the wheel was decreased. Both changes helped to increase the critical speed and move it further away from the operating speed. Although the total wheel weight was decreased, the blade thickness of the new rotor was more than doubled as it was increased from 0.25 inches to 0.625 inches. The new rotor has proven very reliable after several months of service. The new rotor gives more hours running time between washings and it has not eroded enough yet to require rebalancing.

The ID fan inlet and outlet dampers have also suffered from erosion by the slurry carryover. The dampers have had metal replaced several times. Slurry has worked into the bearings; binding the dampers, and, pins have been sheared.

SCRUBBER

The scrubber is more commonly called the A.Q.C. system (Air Quality Control) by the plant personnel. The boiler gas is passed through seven scrubber modules for removal of fly ash and sulfur dioxide. Each module

may be isolated from the gas path with inlet and outlet dampers. The seven modules were originally designed for full boiler load. The boiler load is thus limited whenever a module is removed from service.

The biggest problem with the scrubber is pluggage in the various sections and piping.

The piping systems are all rubber lined to protect the piping from the abrasive qualities of the slurry. We have had some holes wear through the piping in the area of the spent slurry valves. This is the only area holes have appeared and we haven't had any more holes since we stopped modulating with the valve and operating with it either wide open or fully closed.

The venturi section has no internals to plug up, and, except for some coating on the walls in the spray nozzle area, stays very clean. The gas flows through the sump area next making a 180 degree turn, allowing the slurry soaked fly ash to drop out on the sump floor. The slurry then drains through screens into a recirculation tank. The screens set at a 45 degree angle to vertical on the sump floor. The slurry settles on the sump floor and eventually the level becomes high enough to cover most of the sump screen. The sump floor must be cleaned off when a module is removed from service for cleaning and occasionally there are holes in the sump screens to be repaired.

The venturi pump takes suction from the recirculation tank and sprays the slurry through nozzles into the venturi throat. The pump is rubber lined and we have had some trouble tearing rubber liners. The suction strainer for the pump gets plugged up and the pump cavitates. The pump liner is sucked into the impeller when the pump cavitates and the rubbing tears the liner. The suction strainers have plugged up frequently and since they are located in the recirculation tank, the tank must be drained before cleaning the strainer. The venturi spray and wall wash nozzles have also plugged up several times. The nozzles are connected to the piping with rubber hoses about 3 feet long. The nozzles and rubber hoses must be removed and cleaned whenever they plug up. Then the hoses are put back on and the piping is flushed with clearwater to remove the rest of the solidified slurry. The nozzles are then reinstalled and the system is ready to put back in service.

The absorber section of the A.Q.C. module has two parts that plug up frequently. The demister trays are comprised of z-shaped fiberglass boards. The gas flows up from the sump carrying slurry and the slurry coats out on the trays restricting gas flow. The module is shut down to clean the trays when they get dirty.

The reheater section of the absorber also plugs up frequently. The reheater is made up of bundles of steam coils. The gas flows through the coils and is supposed to be heated back up to a minimum of 175°F before passing on to the ID fans. The gas velocity through the demisters is too high for the demisters to remove moisture when the demisters start plugging and slurry carries up to the reheat coils. The coils bake on slurry as it passes through them and can plug up very quickly.

The problems discussed were some of the more involved and time consuming that we confronted. Many repairs and some design changes have been made to the scrubber during the first year turbine inspection. We expect the changes to give us a much more reliable and maintenance free operation. Start up problems are always expected and we believe our first year of operation has given us the experience to maintain a reliable operation while contending with any other problems that may appear.

OUTAGES

There have been 112 outages since the generator was first synchronized to the system on February 23, 1973. Cumulative availability was 48% from June 1, 1973 (start of commercial service) to January 31, 1974. Since the generator was first synchronized to the system on February 23, 1973 there have been 112 outages; 71 less than 24 hours long and 9 longer than one week. A list of outages follows this section of the paper. The "Comments" column gives the type of trip that brought the unit off and additional information concerning the trip or work performed on that outage. The 9 outages longer than 7 days are analyzed as follows:

1 outage - First year turbine inspection
1 " - Scrubber
4 outages - Slag Problems
3 " - Generator Problems

SLAG PROBLEMS:

There are 4 monkey holes spaced across the center of the boiler floor that allow molten slag to run into the slag tanks. The boiler must be brought up to one-third load fairly quickly to get the furnace hot enough for the slag to run properly. B&W recommended that vent lines be installed from the slag tank to the suction of the gas recirculation fans for the purpose of pulling hot gas through the slag taps. The vent would then help the slag to stay hot and run even at low load. The slag tank manufacturer felt that the vent lines might cause problems with the slag tank and didn't encourage the installation of the vent lines. Several attempts were made to fire the boiler fast enough to get the slag to run, but we were not successful and decided to install the vent lines after deslagging the boiler floor 4 times. We have since encountered no serious problems with the vent and have been forced down to deslag twice. The 2 times we were forced down was caused by receiving fire clay with a very high running temperature, and we had to empty the coal bunkers before firing back up.

GENERATOR PROBLEMS:

The generator has forced a short outage 10 times for balance weight changes. Three of the four outages forced for repair were longer than a week. The generator and exciter seal oil seal rings were repaired on all three of these outages and on the first year outage. During outage No. 78 the generator was also reshimmed to distribute the weight of the generator frame so that the foundation would absorb more of the vibration.

SCRUBBER PROBLEMS:

The absorber section of the scrubber contains demister trays and reheater coils which plug up with slurry carried over from the venturi section. We usually have at least one module cut out of service to clean up, but when outage No. 76 came, we were unable to keep up and had to shut down until we could clean enough modules to return to service.

TURBINE ROLL HISTORY

Roll No.	Date	Comments on Turbine Rolls From: First Roll Off Turning Gear With Steam To: First Time Generator Was Synchronized
1	1-25-73	Turbine rolled to 500+ RPM, tripped on false vibration No. 4 bearing.
2	1-25-73	Turbine rolled to 900 RPM for Generator air test, speed was increased to 1200 RPM for test. Turbine was taken off for baffle change in Generator.
3	1-30-73	Turbine rolled to 900 RPM for Generator air test, speed was increased to 1200 RPM for test. Turbine off, leak in boiler and oil pipe change on main pump section.
4	2-08-73	Rolled off turning gear to 2250 RPM, for 10 hour stretchout run. Tripped due to noise in exciter. Broke the shaft on the permanent magnet generator.
5	2-08-73	Rolled main turbine to 2400 RPM. Tripped turbine because of differential expansion, governor end.
6	2-09-73	Rolled to 2400 for 1 hour, continued 3600 for sync. checks. Turbine tripped due to loss of all flame.
7	2-09-73	Turbine rolled off T.G., Unit brought to speed for synchronizing checkout. Unable to synchronize because of wrong ratio on potential transformers.
8	2-22-73	Turbine rolled for 2 minutes and tripped.
9	2-22-73	Unit rolled off turning gear to 1900 RPM, tripped while changing Boiler feed pumps.
10	2-23-73	Unit rolled off turning gear to 1900 RPM. At 5:54 AM La Cygne No. 1 synchronized to system 1st time 6:00 AM. Turbine tripped due to differential expansion, governor end.

OUTAGE RECORD

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
1	2-23	19-11	Outage #1 follows Turbine Roll No. 10
2	2-24	292-54	Controlled - Ran four hour test run at 80 mw load and 2 overspeed trip tests. Shut down to deslag boiler.
3	3-8	25-40	MFT "Loss of All Flame" - Couldn't keep cyclones on.
4	3-9	5-37	" "
5	3-10	225-25	Controlled - Shutdown to deslag boiler.
6	3-20	14-48	Turbine trip "Differential Expansion" -
7	3-21	5-51	MFT "Loss of All Flame". Lost all cyclones when technician shorted a circuit.
8	3-21	40-43	MFT "High Furnace Draft" - "Rotor differential" sensing line on ID fan tore loose and fell into the fan rotor.
9	3-23	8-54	Operator Trip - Fuel oil line broke, no isolation valves, so had to shut down.
10	3-24	0-37	Operator Trip - Superheat temperature dropped, uncontrolled.
11	3-24	2-9	MFT "High Furnace Pressure" - Technician working on scrubber module, dampers went closed.
12	3-24	192-7	Controlled - Unable to keep cyclones on due to wet coal. Boiler needed to be deslagged.
13	4-1	28-52	Controlled - Change balance weights on IP/LP couplings.

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
14	4-3	short	MFT - Trip was caused by closed gas recirculation dampers.
15	4-4	20-18	Operator Trip - Tripped turbine on temperature differential which indicated water detection.
16	4-4	14-44	Generator Lockout Relay "Reverse Power" - Tripped right after synchronization.
17	4-4	short	" " " - Changed setting on reverse current relay.
18	4-6	23-27	Lockout Relay "Auxiliary Transformer "B" Phase Differential" - Transformer was inspected and found a wiring error in "C" phase current transformer.
19	4-6	14-59	Operator Trip - Front generator bearing had 6-mils vibration caused by varying the hydrogen temperature.
20	4-7	19-11	Operator Trip - Relief valve failed on steam supply header to boiler feed pump turbines.
21	4-10	13-09	Operator Trip - Lost cyclones, caused uncontrolled steam temperature drop of more than 150° F.
22	4-11	42-48	Controlled - Boiler tube leaks.
23	4-13	91-30	MFT "Feedwater Flow Unsafe" - Lost the boiler feed pump. Didn't make a transfer quick enough on the boiler feed pump turbine steam supply.
24	4-18	103-25	MFT "High Furnace Pressure" - Had to repair furnace wall damaged by high pressure.

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
25	4-23	94-40	Controlled - Slag tanks full of ash and unable to pull ash.
26	4-27	1-51	MFT "High Furnace Pressure"
27	4-27	1-53	Turbine tripped interceptor valve closed.
28	4-28	0-57	Turbine tripped. Reason unknown.
29	4-28	0-58	4 trips MFT "High Furnace Pressure" - Caused by plugged air preheaters.
30	4-28	25-46	
31	4-29	1-35	
32	4-30	68-55	Shut down to wash the air preheaters.
33	5-3	4-39	MFT "Feedwater Flow Unsafe" - Steam pressure regulator to boiler feed pump turbine malfunctioned and caused steam pressure to swing.
34	5-4	1-44	MFT "Loss of all Flame".
35	5-5	8-20	MFT - Trip was caused by gas recirculation - fan tripping off.
36	5-6	1-2	MFT "Gas Recirc Unsafe" - Cause unknown.
37	5-6	1-26	" " " - This trip was disconnected to have instruments calibrated.
38	5-7	106-19	Controlled - Deslag boiler floor.
39	5-11	8-19	Operator trip - Technician working on control circuit for B&W 201 (pressure reducing) valve caused throttle press. swing.

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
40	5-13	0-59	Operator Trip - Lost cyclones. Turbine temperature differential indicated water detection.
41	5-18	60-44	MFT "High Furnace Pressure" - "B" ID fan tripped off.
42	5-20	7-6	Operator Trip - Turbine vibration.
43	5-21	8-53	Generator Lockout Relay "Excessive Motoring" - Intercept valve went closed.
44	5-21	2-12	Operator Trip - Slag tank full.
45	5-21	2-54	MFT "Feedwater Flow Unsafe" - Caused by intercept valves closing.
46	5-22	16-1	MFT " " " - Lost control of B&W 202 (Primary superheat bypass) valves.
47	5-22	16-53	MFT "Loss of All Flame" - Flame scanner fans tripped off due to water flooding.
48	5-24	18-28	MFT "High Furnace Press" - "A" ID fan tripped from overload.
49	5-25	18-47	MFT "Feedwater Flow Unsafe" - Auxiliary Boilers tripped so B.F.P.T. lost steam pressure.
50	5-26	3-46	Operator Trip - Change balance weight on PMG.
51	5-26	3-16	" " " "
52	5-29	0-47	MFT "Feedwater Flow Unsafe" - Appeared that both Boiler Feed Booster Pumps tripped.

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
53	5-31	1-34	MFT "High Furnace Pressure" - "F" ID fan tripped - cause unknown.
	6-1		June 1, 1973 the Unit is declared available for commercial service.
54	6-3	3-16	Operator Trip - Low steam temp. - Caused by loss of cyclones while burning out bunkers.
55	6-3	2-15	Operator Trip - Excessive water hammer in the flash tank drain header.
56	6-5	322-4	Scheduled Outage - Find cause of vibration in excitor and generator.
57	6-17	10-38	Controlled - Repair leak in 201.1 Pressure Reducing Valve
58	6-17	2-23	Controlled - High vibration on PMG - Made balance weight change.
59	6-18	1-25	MFT "Firing Rate above Reheat Protection Limit" and Diff. pressure sw. across high pressure turbine operated.
60	6-18	0-21	Diff. press sw. above operated again. Disconnected switch.
61	6-19	19-45	Controlled - Unit removed to make a generator balance weight change, attempting to eliminate a seal ring rub.
62	6-20	23-35	Controlled - Made a generator balance weight change.
63	6-25	2-0	MFT "Low Feedwater Flow" - Lost an auxiliary boiler that was supplying Boiler Feed Pump steam.
64	6-27	14-22	Lockout Relay operated "Generator Ground" - "A" phase potential transformer failed.
65	7-2	96-34	Main transformer lockout relay operated - "C"-phased differential - No damage to transformer.

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
66	7-10	24-28	Controlled - Hydrogen leak on the generator lead box.
67	7-11	2-20	" - Made a balance weight change on the PMG.
68	7-13	104-2	" - Slag accumulation on boiler floor - partially removed.
69	7-17	21-24	MFT "Feedwater Flow Unsafe" - B&W 202 (Primary Superheater Bypass) valve control failed.
70	7-18	214-26	Controlled - Slag accumulation on boiler floor.
71	8-2	3-22	MFT "Low Feedwater Flow".
72	8-13	38-1	MFT "High Furnace Draft" - Scrubber plugged up. Unable to maintain adequate Boiler air flow.
73	8-23	3-5	MFT Feedwater Flow Unsafe - Electro-Hydraulic system malfunction.
74	8-27	8-32	MFT "High Furnace Draft" - Scrubber module dampers tripped shut.
75	8-31	2-57	Controlled - Unit was tripped to prevent an employee, who was inspecting a scrubber module from being sucked into the ID fan. Caused by faulty damper operation.
76	9-3	293-15	MFT - Scrubber and air preheaters plugged up.
77	9-16	6-19	MFT "High Furnace Pressure" - ID fan tripped due to lube oil system trouble. Bad timer in control circuit.
78	9-17	443-50	Controlled - Generator hydrogen leak and slag problems.
79	10-7	14-2	" - Made a generator balance weight change.

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
80	10-7	18-36	Controlled - Made a generator balance weight change.
81	10-8	2-16	" - Made a PMG balance weight change.
82	10-9	1-1	MFT - "Total Flame Lost" - Lost fires due to electrician and technician working on vital ac.
83	10-9	2-8	Electrical problems - Lost fire.
84	10-9	15-57	Seal oil problem.
85	10-26	115-35	Controlled - Plugged air preheater and scrubber.
86	10-30	47-57	MFT - Boiler control was placed in automatic with improper setting.
87	11-2	118-20	Controlled - High vibration on PMG and generator caused by hydrogen temperature excursion.
88	11-6	23-27	MFT "Feedwater Flow Unsafe" - Auxiliary boiler tripped. Boiler feed pump steam supply relief valve failed.
89	11-8	11-12	Controlled - Primary superheater tube leak.
90	11-17	25-49	Boiler feed pump tripped on "High Thrust" - No thrust bearing damage was found.
91	11-19	16-11	MFT "Feedwater Flow Unsafe" - Boiler feed pump tripped from low deaerator level.
92	11-20	38-47	Controlled - Air preheaters plugged up.
93	11-22	23-31	Operator trip - Indication of low throttle pressure.

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
94	12-2	45-3	Controlled - Air preheater plugged up.
95	12-6	71-24	MFT "Feedwater Flow Unsafe" - Pressure transmitter froze up and backed down the boiler feed pump.
96	12-17	153-5	MFT "Feedwater Flow Unsafe" - Boiler feed pump tripped.
97	12-24	200-7	Controlled - Hydrogen seal ring failed.
98	1-3	98-36	MFT - Boiler Feed Booster Pump was tripped by a pressure switch mis-operation.
99	1-7	35-21	Controlled - Had to replace broken bolts on B&W 207 (Secondary Superheat Bypass) valve.
100	1-9	20-18	Lockout Relay "Differential Expansion" - No expansion problem, a pick-up coil failed on the expansion indicator.
101	1-10	23-6	Operator Trip - Indication of generator end differential expansion.
102	1-12	148-33	Controlled - Coal problems, cyclone feeder stoppage and unable to convey coal.
103	1-18	32-46	Controlled - B&W 207 (Secondary Superheater Bypass) valve discharge line leak. Also had to replace broken bolts on the impingment flange.
104	1-26	73-44	Controlled - Boiler tube leak at No. 2 slag tap. Caused by using a jackhammer to open the tap hole.
105	1-31	1-36	Operator trip - Control of B&W 201 (Pressure Reducing) valve failed. Caused uncontrolled steam temperature drop.

Outage No.	Date Started	Length	Type of Trip - Reason for Trip
106	1-31	1-12	Operator Trip - Control of B&W 201 (Pressure Reducing) valve failed. Caused uncontrolled steam temperature drop.
107	2-4	6-38	MFT "Low Feedwater Flow" - Cold reheat steam supply to the boiler feed pump turbine pressure regulating valve failed.
108	2-6	6-1	MFT "High Furnace Draft" - Scrubber plugged up, unable to maintain adequate boiler air flow.
109	2-9	17-59	Same as above.
110	2-10	5-38	Operator Trip - Uncontrolled steam temperature drop caused by losing cyclones.
111	2-10	1-24	Operator Trip - B&W 201 valve control failed. Caused uncontrolled steam temperature drop.
112	2-16		Controlled - First year turbine-generator outage.